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Creating a Culture of Compliance

BACKGROUND

Outlined below is recent standards and compliance activity at NERC, NAESB and the Regional Entities. If you have comments for MISO consideration send them to standards&compliance@misoenergy.org

To facilitate communication regarding particular issues, two exploder lists have been created. The lists are titled, NERC_NAESB Monthly Update (join this list to receive this monthly report on NERC, NAESB, and Regional Activities), and Standards Collaboration (join this list to participate in meetings and receive communications on collaborating on comments to new and revised standards).

To join, please go to https://extranet.midwestiso.org. If you do not have an existing account, you will need to create one. Once you have created an account, click on "update account information," and check the box for the exploder/s you would like to join.

DEADLINES

NERC/NAESB/Regional Deadline Table		
Due Date	**Deliverable**	**Entity**
11/23/11	Close of Ballot Pool Window for Project 2007-12: Frequency Response	NERC
11/28/11	Close of Ballot Pool Window for Project 2009-01: Disturbance and Sabotage Reporting	NERC
11/29/11	Opening of Initial Ballot and Non-Binding Poll Window for Project 2007-12: Frequency Response	NERC
12/2/11	Opening of Initial Ballot Window for Project 2009-01: Disturbance and Sabotage Reporting	NERC
12/5/11	Close of Comment Period for VAR-001-2 WECC Variance	NERC
12/8/11	Close of Formal Comment Period for Project 2007-12: Frequency Response	NERC
12/8/11	Close of Initial Ballot and Non-Binding Poll for Project 2007-12: Frequency Response	NERC
12/12/11	Close of Formal Comment Period for Project 2009-01: Disturbance and Sabotage Reporting	NERC
12/12/11	Close of Initial Ballot Window for Project 2009-01: Disturbance and Sabotage Reporting	NERC
12/15/11	Data Submittal - BAL-001-0- Real Power Balancing Control Performance (CPS 1 & CPS 2): November, 2011	RFC
12/15/11	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – November, 2010	RFC/ NERC
12/15/11	Close of Ballot Pool for Project 2008-06: Cyber Security Order 706 Version 5 CIP	NERC
12/16/11	Opening of Twelve Initial Ballot Windows for ten Standards, Implementation Plan and Definitions for Project 2008-06: Cyber Security Order 706 Version 5 CIP	NERC
12/22/11	Close of Comment Period for Proposed Changes to the NERC Rules of Procedure and Associated Appendices	NERC
12/22/11	Close of Comment Period for PRC-006-NPCC-1	NERC
1/6/12	Close of Formal Comment Period for Project 2008-06: Cyber Security Order 706 Version 5 CIP	NERC
1/6/12	Close of Twelve Initial Ballot Windows for ten Standards, Implementation Plan and Definitions for Project 2008-06: Cyber Security Order 706 Version 5 CIP	NERC

FERC

FERC Orders of Note

November 07, 2011

FERC Staff Report on Demand Response and Advanced Metering

November 8, 2011

FERC Staff's Plan for Retrospective Analysis of Existing Rules Docket No. AD12-6-000

Notice of Technical Conference on Voltage Coordination on High Voltage Grids Docket No. AD12-5-000

November 9, 2011

FERC Follow Up Actions for SPP RE, Texas RE and WECC in Response to August 16, 2011 Joint Report Docket No. AD11-9-000

November 10, 2011

Second Notice of Technical Conference on Policy Issues Relating to the Reliability of the Bulk Power System

November 14, 2011

Request for Evidence of Commissioner Moeller on EPA Issues for the November 2011 Reliability Conference Docket Nos. AD12-1-000, RC11-6-000, and EL11-62-000

November 15, 2011

Letter Order Approving CMEP Agreements Between WECC and NPCC and Related Amendments to Delegation Agreements Docket No. RR11-2-000

November 17, 2011

Order Approving Amendments to NERC RoP Appendices 3B and 3D Docket No. RR11-5-000

Order Denying Rehearsing and Partially Granting Clarification Regarding Cedar Creek and Milford Compliance Registry Appeals Docket Nos. RC11-2-001 and RC11-1-001

Order Approving Reliability Standard FAC-013-2 Docket No. RD11-3-000

Order Denying Rehearing of SPP RE and NPPD's Requests for Rehearing of FERC's July 21, 2011 Order Denying Petitions for Review Docket No. RR11-1-002

Order Approving Reliability Standard FAC-008-3 Docket No. RD11-10-000

NERC Filings to FERC

November 07, 2011

Compliance Filing in Response to the October 7, 2011 Order Docket No. RR10-11-000

November 10, 2011

Joint Motion for Extension of Time to Submit Compliance Filing Docket Nos. RC11-1-000 and RC11-2-000

November 14, 2011

Motion for Leave to Answer and Answer Docket No. RC11-6-000

Petition for Approval of a Revision to the Rules of Procedure – Correction to Section 1.3 of Appendix 4D Docket No. RR11-__-000

November 21, 2011

Comments in Response to NOPR on Reliability Standard PRC-023-2 Docket No. RM11-16-000

Comments in Response to NOPR on Version 4 CIP Reliability Standards Docket No. RM11-11-000

November 22, 2011

Motion for Extension of Time regarding System Personnel Training Reliability Standard Docket No. RM09-25-000

Motion for an Extension of Time Regarding a New Generator Relay Loadability Reliability Standard Docket No. RM08-13-001

Petition of NERC for Approval of Amendments to Delegation Agreement with WECC – Amendments to WECC's Bylaws and Regional Reliability Standards Development Procedure Docket No. RR12-__-000

November 23, 2011

Third Quarter 2011 Compliance Filing of the North American Electric Reliability Corporation in Response to Paragraph 629 of Order No. 693 Docket No. RM06-16-000

NERC

Standards Under Development

Click Picture for Link to NERC Reliability Standards Under Development Page

Reliability Standards Under Development			
Project	**Action**	**Start Date**	**End Date**
Current and Pending Ballots (Sorted by End Date)			
Project 2007-12 – Frequency Response	Initial Ballot and Non-Binding Poll	11/30/11	12/08/11
Project 2009-01 – Disturbance and Sabotage Reporting – CIP-001 and EOP-004	Initial Ballot and Non-Binding Poll	12/02/11	12/12/11
Project 2008-06 – Cyber Security – Order 706 – CIP-002 through CIP-009 (Version 5 CIP Standards)	Initial Ballots Please vote for each of the 10 CIP standards separately	12/16/11	01/06/12
Join Ballot Pools (Ballot Pool Windows Close at 8 a.m. Eastern)			
Project 2008-06 – Cyber Security – Order 706 – CIP-002 through CIP-009 (Version 5 CIP Standards)	Join Ballot Pool	11/07/11	12/15/11
Posted for Comment (Closes at 8 p.m. Eastern) (Sorted by End Date)			
Regional Reliability Standard VAR-001-2 WECC Variance	Comment Form	10/20/11	12/05/11
Project 2007-12 – Frequency Response	Comment Form	10/25/11	12/08/11
Project 2009-01 – Disturbance and Sabotage Reporting – CIP-001 and EOP-004	Comment Form	10/28/11	12/12/11
Project 2008-06 – Cyber Security – Order 706 – CIP-002 through CIP-009 (Version 5 CIP Standards)	Comment Form	11/07/11	01/06/12

NERC
Ballot Results
See more information on the NERC Ballot Results web page

Initial Ballot Results

- Project 2009-22: Interpretation of COM-002-2 for ISO-RTO Council

Voting statistics are listed below

Quorum: 91.2%

Approval: 95.05%

The drafting team will consider all comments received, and decide whether to make additional changes to the interpretation.

- Project INT-2011-01: Revision of MOD-028-1 to address FPL Request for Interpretation

Voting statistics are listed below

Quorum: 88.05%

Approval: 85.53%

The drafting team will consider all comments received, and decide whether to make additional changes to the interpretation.

- Project 2010-07: Generator Requirements at the Transmission Interface

Voting statistics are listed below

FAC-001-1

Quorum: 88.22%

Approval: 86.94%

FAC-003-3

Quorum: 85.08%

Approval: 85.71%

FAC-003-X

Quorum: 84.82%

Approval: 85.31%

PRC-004-2.1

Quorum: 84.29%

Approval: 96.09%

The drafting team will consider all comments received, and decide whether to make additional changes to the interpretation.

Recirculation Ballot Results

- Project 2010-17 Definition for Bulk Electric System

Voting statistics are listed below

BES Definition

Quorum: 95.92%

Approval: 81.32%

Detailed Information to Support a Request for BES Exception

Quorum: 93.02%

Approval: 81.48%

The drafting team will consider all comments received, and decide whether to make additional changes to the interpretation.

Successive Ballot Results

- Project 2008-10: Interpretation of CIP-006-x R1 for Progress Energy

Voting statistics are listed below

Quorum: 83.53%

Approval: 95.99%

The drafting team will post the interpretation and consideration of comments for a recirculation ballot

Final Ballot Results

- None

NERC Miscellaneous News

- The NERC Board Approved the Vegetation Management Standard FAC-003-2 at their November 3 BOT Meeting. A summary of the meeting can be found here.
- NERC's Spare Equipment Database Task Force announced the development of a spare equipment database that allows the industry to track spare long-lead time transformers. Read the full announcement here.
- More than 75 industry and government partners participated in GridEx 2011, NERC's first cybersecurity readiness exercise. Read the full announcement here
- NERC has posted its 2011 Long-Term Reliability Assessment here.
- NERC has posted its 2011/2012 Winter Assessment here.
- NERC Standards 101 Webinar Posted here.
- Two new lessons learned have been posted on the NERC website under "Events Analysis – Lessons Learned"
- The October 2011 NERC Newsletter can be found here.

REGIONAL ENTITIES

Reliability*First*

- The October RFC Newsletter can be found here.
- RFC CMEP Update


2011 CIP Audit Schedule Rev. 13.xls


2011 RFC Compliance Monitoring Schedule

Midwest Reliability Organization (MRO)

- Find the November/December edition of the MRO Midwest Reliability Matters Newsletter Here.
- Find the MRO Standards page here.
- Find the MRO Compliance page here.

SERC

- The SERC 2012 Implementation Plan has been posted here.
- See the latest SERC news here.
- Find the SERC Standards page here.

NAESB

Recent NAESB Activity

- Membership Ratified:
  - ATC Change Narrative and Zero ATC Narrative Postings recommendation (11/28)
  - Consistency Changes for OASIS Business Practice Standards recommendation (11/28)

Upcoming NAESB Activity

- Network Integration Transmission Service (NITS) on OASIS recommendation will be posted for a 75 day formal comment period (TBD)

NAESB Subcommittee Information

WEQ Business Practices Subcommittee (BPS)

- Information on the *Business Practices Subcommittee* is posted at: http://www.naesb.org/weq/weq_bps.asp

- The *Business Practices Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf3/weq_bps_exploder.pdf

WEQ OASIS Subcommittee:

- Information on the *OASIS Subcommittee* is posted at: http://www.naesb.org/weq/weq_oasis.asp

- The *OASIS Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf4/weq_oasis_exploder.pdf

WEQ Joint Electric Scheduling Subcommittee (JESS):

- Information on the Joint Electric Scheduling Subcommittee is posted at: http://www.naesb.org/weq/weq_jess.asp

- The *Joint Electric Scheduling Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf4/weq_jess_exploder.pdf:

WEQ Standards Review Subcommittee (SRS):

- Information on the *Standards Review Subcommittee* is posted at: http://www.naesb.org/weq/weq_standards_review.asp

- The *Standards Review Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf3/weq_srs_exploder.pdf

WEQ Public Key Infrastructure Subcommittee (PKIS):

- Information on the Public Key Infrastructure Subcommittee is posted at: http://www.naesb.org/weq/weq_pki.asp

- The Public Key Infrastructure Subcommittee has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf4/weq_pkis_exploder.pdf

COMPLIANCE CALENDAR

December 2011						
Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
			1	2 NERC Webinar: Organization Registration and Certification Update	3	4
5	6 NERC Compliance Workshop Atlanta, GA	7	8	9	10	11
12	13 NERC Webinar: Project 20008-06 1:00 – 2:00	14 MRO Compliance and Enforcement Workshop	15 MRO Annual Member and BOD Meeting	16	17	18
19	20	21	22	23	24	25
26	27	28	29	30	31	

Future Meetings

- NERC
  - For the complete NERC Meeting schedule, see: http://www.nerc.net/meetings/
- RFC
  - For the complete RFC Meeting schedule, see: https://www.rfirst.org/Pages/Calendar.aspx
- MRO
  - For the complete MRO Meeting schedule, see http://www.midwestreliability.org/meetings.html
- SERC
  - For the complete SERC Meeting schedule, see: http://www.serc1.org/Application/UpcomingMeetingsView.aspx
- NAESB
  - For the complete SERC Meeting schedule, see: http://www.naesb.org/monthly_calendar.asp



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Monthly NERC, NAESB, Regional Entity Update

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DEADLINES

NERC/NAESB/Regional Deadline Table		
Due Date	**Deliverable**	**Entity**
1/3/12	Opening of Three Successive Ballot Windows for Project 2007-03: Real-Time Transmission Operations	NERC
1/12/12	Close of Three Successive Ballot Windows for Project 2007-03: Real-Time Transmission Operations	NERC
1/12/12	Close of Formal Comment Period for Project 2007-03: Real-Time Transmission Operations	NERC
1/6/12	Close of Formal Comment Period for Project 2008-06: Cyber Security Order 706 Version 5 CIP	NERC
1/6/12	Close of Twelve Initial Ballot Windows for ten Standards, Implementation Plan and Definitions for Project 2008-06: Cyber Security Order 706 Version 5 CIP	NERC
1/15/12	Data Submittal - BAL-001-0- Real Power Balancing Control Performance (CPS 1 & CPS 2): December, 2011	RFC
1/15/12.	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – December, 2010	RFC/ NERC
1/15/12	Data Submittal – BAL-002-0 Disturbance Control Performance	RFC
2/15/12	Data Submittal - BAL-001-0- Real Power Balancing Control Performance (CPS 1 & CPS 2): January, 2012	RFC
2/15/12.	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – January, 2012	RFC/ NERC

FERC

FERC Orders of Note

December 1, 2011

Approving Stipulation and Consent Agreement – PacifiCorp Docket No. IN11-6-000

December 15, 2011

Order Approving Interpretation of EOP-001-0 Requirements R1 and R3.2 Docket No. RD11-12-000

NERC Filings to FERC

December 2, 2011

Compliance Filing in Accordance with the June 16, 2011 Order Docket Nos. RC11-1-000 and RC11-2-000

Response to Request for Production and Request for Confidential Treatment Docket No. RC11-5-000

December 5, 2011

Reply Comments in Response to Notice of Proposed Rulemaking on CIP Version 4 Reliability Standards Docket No. RM11-11-000

December 13, 2011

NERC Standards Development Plan 2012 – 2014 Informational Filing Pursuant to Section 310 of the NERC Rules of Procedure Docket Nos. RM05-17-000, RM05-25-000, RM06-16-000

December 21, 2011

Comments of NERC in Response to NOPR on Transmission Planning Reliability Standards Table 1, Footnote 'b' Docket No. RM11-18-000

Petition for Approval of Proposed Reliability Standard FAC-003-2 Transmission Vegetation Management Docket No. RM__-__-___

December 23, 2011

NERC Submits Comments on UFLS NOPR Docket No. RM11-20-000

NERC

Standards Under Development

Click Picture for Link to NERC Reliability Standards Under Development Page

Reliability Standards Under Development			
Project	**Action**	**Start Date**	**End Date**
Current and Pending Ballots (Sorted by End Date)			
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)	**Initial Ballots Please vote for each of the 10 CIP standards separately**	12/16/11	01/06/12
Project 2007-03 — Real-time Transmission Operations — TOP-001-2, TOP-002-3 and TOP-003-2	**Successive Ballots and Non-Binding Polls**	01/03/12	01/12/12
Join Ballot Pools (Ballot Pool Windows Close at 8 a.m. Eastern)			
Posted for Comment (Closes at 8 p.m. Eastern) (Sorted by End Date)			
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)	**Comment Form**	11/07/11	01/06/12
Project 2007-03 — Real-time Transmission Operations — TOP-001-2, TOP-002-3 and TOP-003-2	**Comment Form**	12/14/11	01/12/12
Order 754 — Request for Data or Information	**Comment Form**	12/22/11	02/06/12

NERC
Ballot Results
See more information on the NERC Ballot Results web page

Initial Ballot Results

- Project 2007-12: Frequency Response

Voting statistics are listed below

Quorum: 93.92%

Approval: 30.82%

The drafting team will consider all comments received during the comment period and ballot

- Project 2009-01 Disturbance and Sabotage Reporting

Voting statistics are listed below

Quorum: 87.97%

Approval: 36.21%

The drafting team will consider all comments received during the comment period and ballot

Recirculation Ballot Results

- None

Successive Ballot Results

- None

Final Ballot Results

- None

NERC Miscellaneous News

- The NERC Registration and Certification Webinar Slides have been posted here.
- NERC's Report, The 2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States, has been posted here.
- The Compliance Enforcement Initiative – 3 Month Status Update Webinar slides have been posted here.
- The Project 2008-06 Cyber Security Order 706 Webinar slides have been posted here.
- The Physical Security Webinar slides have been posted here.
- The November 2011 NERC Newsletter can be found here.

REGIONAL ENTITIES

Reliability*First*

- The November/December RFC Newsletter can be found here.
- RFC CMEP Update



2012 RFC Compliance Monitoring Schedule

Midwest Reliability Organization (MRO)

- Find the November/December edition of the MRO Midwest Reliability Matters Newsletter Here.
- Find the MRO Standards page here.
- Find the MRO Compliance page here.

SERC

- The SERC 2012 Implementation Plan has been posted here.
- See the latest SERC news here.
- Find the SERC Standards page here.

NAESB

Recent NAESB Activity

- On December 8, 2011, the NAESB Board of Directors approved the Wholesale Electric Quadrant's 2012 Annual Plan (http://www.naesb.org/pdf4/bd120811a7.docx). The plan identifies activities where the Wholesale Electric Quadrant will focus its resources in developing standards during 2012.
- NAESB posted for formal comments the Clarification Recommendation C11004 (http://www.naesb.org/pdf4/weq_c11004_rec.docx) that supports an entity's ability to modify the Source and/or Sink on a long-term firm reservation without having to modify the Point of Receipt (POR) or Point of Delivery (POD). Comments are due on January 11, 2012
- NAESB posted the Standards Recommendation for Network Integration Transmission Service (NITS) on OASIS. This link http://www.naesb.org/pdf4/weq_121311_reqcom.docx is the request for comments which contains links to the recommendation and all of the changes to the WEQ Business Practice Standards including WEQ-000, -001, -002, -003, -013. Due to the volume of standards being added, NAESB has posted the recommendation for a 75-day comment period. Comments are due on February 27, 2012.
- On January 5-6, 2012 the Joint Electric Scheduling Subcommittee will meet. One of the key topics for discussion will be the transition of the NERC TSIN Registry functions from NERC to the NAESB Electric Industry Registry. It is expected that entities will be required to use the new Electric Industry Registry (webRegistry hosted by OATI) in second quarter 2012. Information for this meeting, which is available via webcast, is posted at: http://www.naesb.org/pdf4/weq_jess010512a.doc
- On January 24, 2012, NAESB will hold a review session, via webcast, for the industry to better understand what is included in the NITS on OASIS proposed standards. Information about the webcast is available at: http://www.naesb.org/pdf4/weq_ec012412a.doc.

Note the NAESB meetings listed are open to anyone regardless of NAESB membership.

NAESB Subcommittee Information

WEQ Business Practices Subcommittee (BPS)

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WEQ OASIS Subcommittee:

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WEQ Joint Electric Scheduling Subcommittee (JESS):

- Information on the Joint Electric Scheduling Subcommittee is posted at: http://www.naesb.org/weq/weq_jess.asp
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WEQ Public Key Infrastructure Subcommittee (PKIS):

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COMPLIANCE CALENDAR

January 2012						
Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
						1
2	3	4	5	6	7	8
9	10	11	12	13	14	15
16	17	18	19	20	21	22
23	24	25	26	27	28	29
30	31					

Future Meetings

- NERC
  - For the complete NERC Meeting schedule, see: http://www.nerc.net/meetings/
- RFC
  - For the complete RFC Meeting schedule, see: https://www.rfirst.org/Pages/Calendar.aspx
- MRO
  - For the complete MRO Meeting schedule, see http://www.midwestreliability.org/meetings.html
- SERC
  - For the complete SERC Meeting schedule, see: http://www.serc1.org/Application/UpcomingMeetingsView.aspx
- NAESB
  - For the complete SERC Meeting schedule, see: http://www.naesb.org/monthly_calendar.asp



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DEADLINES

NERC/NAESB/Regional Deadline Table		
Due Date	**Deliverable**	**Entity**
2/3/12	Close of Comment Period for Project 2010-17: Definition of Bulk Electric System Phase 2	NERC
2/6/12	Close of Comment Period for Order 754: Request for Data or Information in Accordance with NERC Rule of Procedure 1600	NERC
2/8/12	Close of Formal Comment Period for Project 2006-06: Reliability Coordination	NERC
2/8/12	Close of Three Ballot Windows and Three Non-Binding Poll Windows for Project 2006-06: Reliability Coordination	NERC
2/15/12	Data Submittal - BAL-001-0- Real Power Balancing Control Performance (CPS 1 & CPS 2): January, 2012	RFC
2/15/12	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – January, 2012	RFC/ NERC
2/20/12	Close of Comment Period for BAL-002-WECC-1	WECC/NERC
3/9/12	Close of Comment Period for BAL-001.-0.1a (WECC Variance)	WECC/NERC
3/9/12	Close of Comment Period for BAL-004-WECC-02: Automatic Time Error Correction	WECC/NERC
3/15/12	Data Submittal - BAL-001-0- Real Power Balancing Control Performance (CPS 1 & CPS 2): February, 2012	RFC
3/15/12	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – February, 2012	RFC/ NERC

FERC

FERC Orders of Note

January 10, 2012

Letter Order Approving Revisions to Appendix 4D of the NERC Rules of Procedure Docket No. RR12-1-000

January 27, 2012

Order on Notices of Penalty – December 30, 2011 Notices of Penalty

January 31, 2012

Order Approving Amendments to Rules of Procedure Docket No RR12-3-000

NERC Filings to FERC

January 6, 2012

Informational Filing Regarding Paragraph 773 of Order No. 672 Docket Nos. RR09-7-000 and RR10-11-000

January 11, 2012

Answer to Comments Regarding Compliance Filing for Cedar Creek Wind Energy and Milford Wind Corridor Phase 1 Docket Nos. RC11-1-000 and RC11-2-000

January 17, 2012

Compliance Filing in Response to November 17, 2011 Order Approving Reliability Standard FAC-008-3 Docket No. RD11-10-___

Compliance Filing in Response to November 17, 2011 Order Approving Reliability Standard FAC-013-2 Docket No. RD11-3-___

January 23, 2012

NERC Submits Supplemental Information Regarding SMUD NOP Docket No. NP12-8-000

January 25, 2012

Petition for Approval of a Revised Definition of "Bulk Electric System" in the NERC Glossary of Terms Used in Reliability Standards Docket No. RM12-6-000

Petition for Approval of Revisions to its Rules of Procedure to Adopt a Bulk Electric System Exception Procedure Docket No. RR__-__-___

January 31, 2012

Informational Report of NERC on Analysis of Standards Process Results for the Fourth Quarter 2011 Docket Nos. RR06-1-000 and RR09-7-000

NERC

Standards Under Development

Click Picture for Link to NERC Reliability Standards Under Development Page

Reliability Standards Under Development			
Project	**Action**	**Start Date**	**End Date**
Current and Pending Ballots (Sorted by End Date)			
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)	**Initial Ballots Please vote for each of the 10 CIP standards separately**	12/16/11	01/06/12
Project 2007-03 — Real-time Transmission Operations — TOP-001-2, TOP-002-3 and TOP-003-2	**Successive Ballots and Non-Binding Polls**	01/03/12	01/12/12
Join Ballot Pools (Ballot Pool Windows Close at 8 a.m. Eastern)			
Posted for Comment (Closes at 8 p.m. Eastern) (Sorted by End Date)			
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)	**Comment Form**	11/07/11	01/06/12
Project 2007-03 — Real-time Transmission Operations — TOP-001-2, TOP-002-3 and TOP-003-2	**Comment Form**	12/14/11	01/12/12
Order 754 — Request for Data or Information	**Comment Form**	12/22/11	02/06/12

NERC
Ballot Results
See more information on the NERC Ballot Results web page

Initial Ballot Results

- Project 2008-06: Cyber Security Order 706 (CIP Version 5)

Initial ballot results for CIP-002-5 thru CIP-011-5, CIP V5 Implementation Plan and CIP V5 Definitions can be found here.

The drafting team will consider all comments and determine what changes to make to each of the standards, the implementation plan, and the definitions.

Recirculation Ballot Results

- Project 2010-07: Generator Requirements at the Transmission Interface

Voting statistics are listed below

FAC-001-1

Quorum: 88.48%

Approval: 90.10%

FAC-003-3

Quorum: 87.17%

Approval: 85.38%

FAC-003-X

Quorum: 86.91%

Approval: 85.03%

PRC-004-2.1a

Quorum: 86.65%

Approval: 96.43%

Non-binding polls of the modified VRFs and VSLs will be conducted, and the standards will be presented to the NERC BOT for action. If adopted, the standards will be filed with regulatory authorities.

- Project INT-2011-01: Interpretation of MOD-0281 for FPL

Voting statistics are listed below

Quorum: 90.10%

Approval: 92.49%

Non-binding polls of the modified VRFs and VSLs will be conducted, and the standards will be presented to the NERC BOT for action. If adopted, the standards will be filed with regulatory authorities.

Successive Ballot Results

- Project 2007-03: Real Time Operations

Voting statistics are listed below

TOP-001-2

Quorum: 82.04%

Approval: 59.93%

TOP-002-3

Quorum: 82.04%

Approval: 77.08%

TOP-003-2

Quorum: 82.04%

Approval: 78.95%

The drafting team will consider all comments and determine what changes to make to each of the standards, the implementation plan, and the definitions.

Final Ballot Results

- None

NERC Miscellaneous News

- The Order 754 – Data Request Webinar is has been posted here.
- Three new lessons learned have been posted on the NERC website, and can be found here
- The December 2011 NERC Newsletter can be found here.
- The January 2012 NERC Newsletter can be found here.

REGIONAL ENTITIES

Reliability*First*

- The January RFC Newsletter can be found here.
- RFC CMEP Update



2012 RFC Compliance Monitoring Schedule

Midwest Reliability Organization (MRO)

- Find the January/February edition of the MRO Midwest Reliability Matters Newsletter Here.
- Find the MRO Standards page here.
- Find the MRO Compliance page here.

SERC

- The SERC 2012 Implementation Plan has been posted here.
- See the latest SERC news here.
- Find the SERC Standards page here.

NAESB

Recent NAESB Activity

TSIN Registry

- **If you have not heard, the NERC Transmission Service Information Network (TSIN) Registry is going away. It will be replaced by the Electric Industry Registry under, NAESB's purview. The EIR will be webRegistry tool developed and managed by OATI. If you are registered in the TSIN registry you will need to register in the new registry. NAESB and OATI are having a number of 90 minute Information Sessions to familiarize the industry with the new tool. These sessions start on Thursday February 2nd. The exact dates and times are posted on the NAESB website. If you are interested in interested in participating in one of these sessions contact NAESB at www.naesb.org or 713-356-0060.**

NAESB Subcommittee Information

WEQ Business Practices Subcommittee (BPS)

- Information on the *Business Practices Subcommittee* is posted at: http://www.naesb.org/weq/weq_bps.asp
- The *Business Practices Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf3/weq_bps_exploder.pdf

WEQ OASIS Subcommittee:

- Information on the *OASIS Subcommittee* is posted at: http://www.naesb.org/weq/weq_oasis.asp
- The *OASIS Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf4/weq_oasis_exploder.pdf

WEQ Joint Electric Scheduling Subcommittee (JESS):

- Information on the Joint Electric Scheduling Subcommittee is posted at: http://www.naesb.org/weq/weq_jess.asp
- The *Joint Electric Scheduling Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf4/weq_jess_exploder.pdf:

WEQ Standards Review Subcommittee (SRS):

- Information on the *Standards Review Subcommittee* is posted at: http://www.naesb.org/weq/weq_standards_review.asp
- The *Standards Review Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf3/weq_srs_exploder.pdf

WEQ Public Key Infrastructure Subcommittee (PKIS):

- Information on the Public Key Infrastructure Subcommittee is posted at: http://www.naesb.org/weq/weq_pki.asp
- The Public Key Infrastructure Subcommittee has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf4/weq_pkis_exploder.pdf

COMPLIANCE CALENDAR

February 2012

Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
		1	2 NERC Webinar CEI FFT Update 1:00 – 2:30 PM	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23 NERC Seminar ERO Auditor Overview 12:00 – 5:00	24 NERC Seminar ERO Auditor Overview 8:00 – 12:00	25	26
27	28	29				

Future Meetings

- NERC
  - For the complete NERC Meeting schedule, see: http://www.nerc.net/meetings/
- RFC
  - For the complete RFC Meeting schedule, see: https://www.rfirst.org/Pages/Calendar.aspx
- MRO
  - For the complete MRO Meeting schedule, see http://www.midwestreliability.org/meetings.html
- SERC
  - For the complete SERC Meeting schedule, see: http://www.serc1.org/Application/UpcomingMeetingsView.aspx
- NAESB
  - For the complete SERC Meeting schedule, see: http://www.naesb.org/monthly_calendar.asp

NPCC, Inc.

Dress Will Be Business Casual

Agenda

Northeast Power Coordinating Council, Inc.
2011 General Meeting

"Providing Reliability & Meeting Expectations"

Toronto Marriott Bloor Yorkville
90 Bloor Street East
Toronto, Ontario M4W 1A7

1:00 PM to 5:00 PM – Wednesday, November 30, 2011

Welcome & Opening Remarks

Harvey Reed, NPCC Chairman of the Board

Edward A. Schwerdt, NPCC President & CEO

Herb Schrayshuen, Vice President - Standards and Training, NERC

Defining the Bulk Electric System (BES)

Peter Heidrich, Chair, NERC BES Drafting Team
Florida Reliability Coordinating Council

Kenneth C. Lotterhos, Esq., NERC Rules of Procedure Development Team
Managing Director, Navigant Consulting, Inc.

Break

Cyber-Security
Greg Goodrich
Chair, NPCC Task Force on Infrastructure Security & Technology
New York ISO

Ontario's Experience
Paul Murphy
President & CEO
Independent Electricity System Operator

Closing Remarks
Philip A. Fedora, Assistant Vice President of Reliability Services
NPCC

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Andrianne S. Payson at 212-259-8218.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Role & Initiatives

November 30, 2011

Herb Schrayshuen

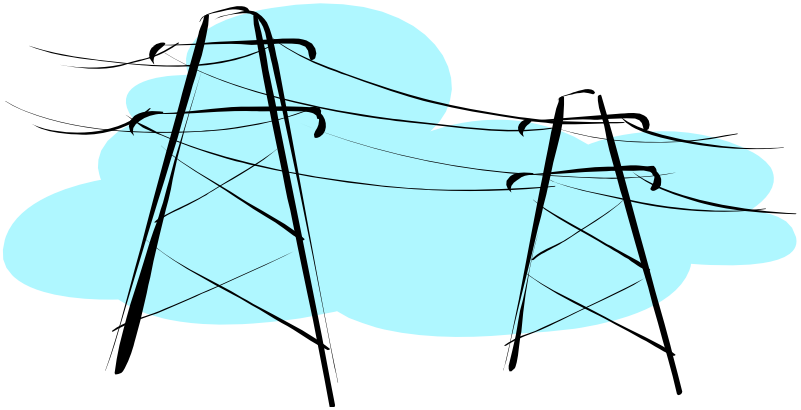
RELIABILITY | ACCOUNTABILITY






What is NERC's role?

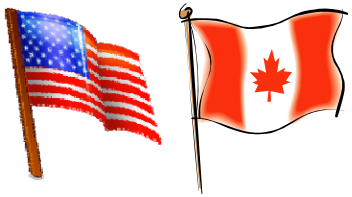
- Mission: Ensure the reliability of the North American bulk power system by…
  - Acting as a catalyst for positive change towards improving reliability
  - Holding entities accountable for reliability results



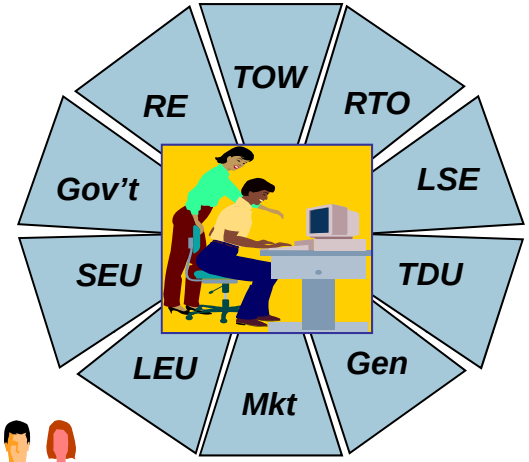
Roles and Responsibilities



NERC Board of Trustees



Regulators



Ballot Body



Standing Committees

Regional Organizations





Stakeholders



NERC & Regional Staff

Drafting Teams



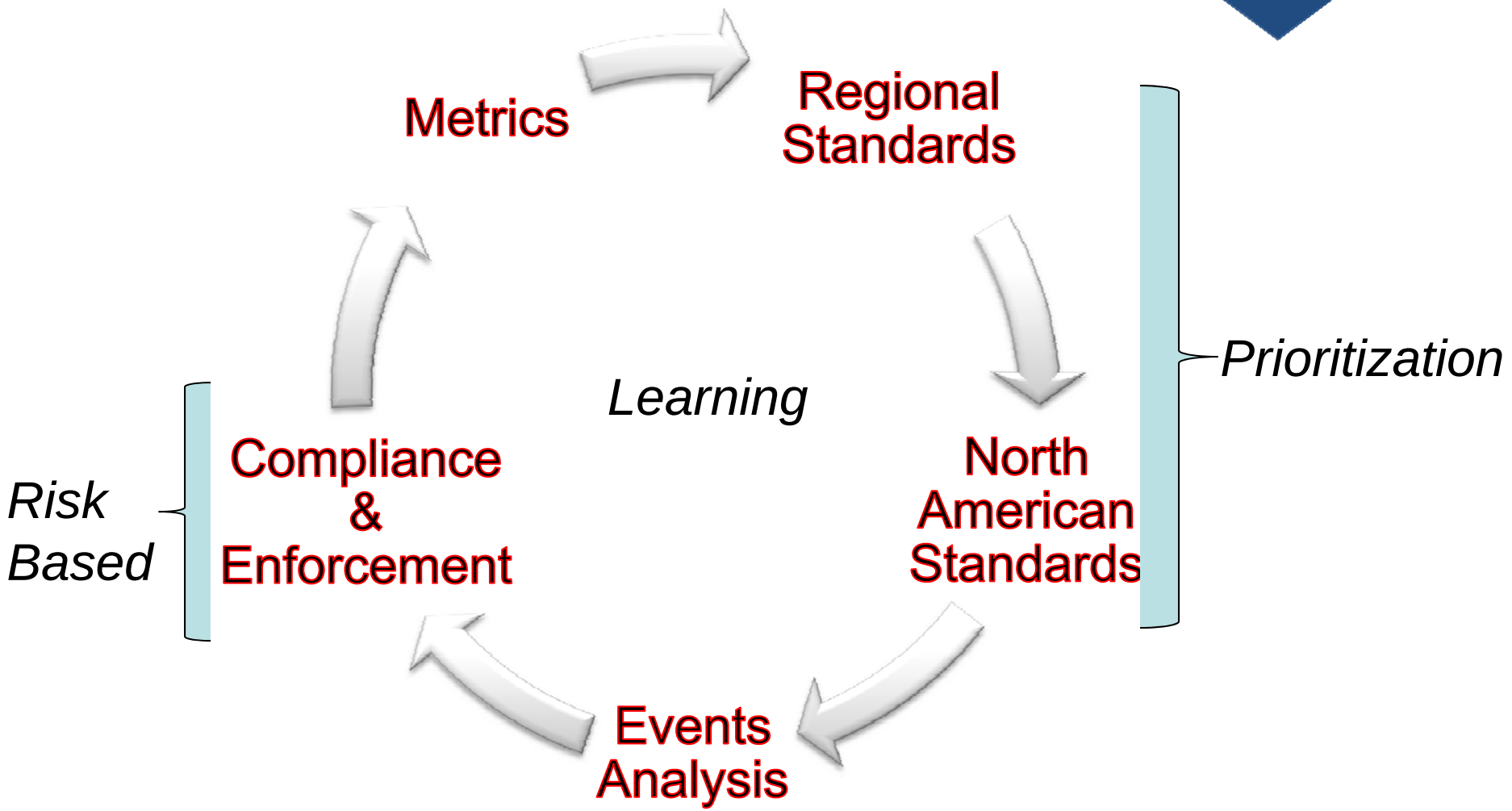
Ballot Pools



Four Pillars

- Reliability
- Accountability
- Learning
  - NERC
  - Industry
- Risk based decision making
  - How do we allocate limited resources?

Process Flow



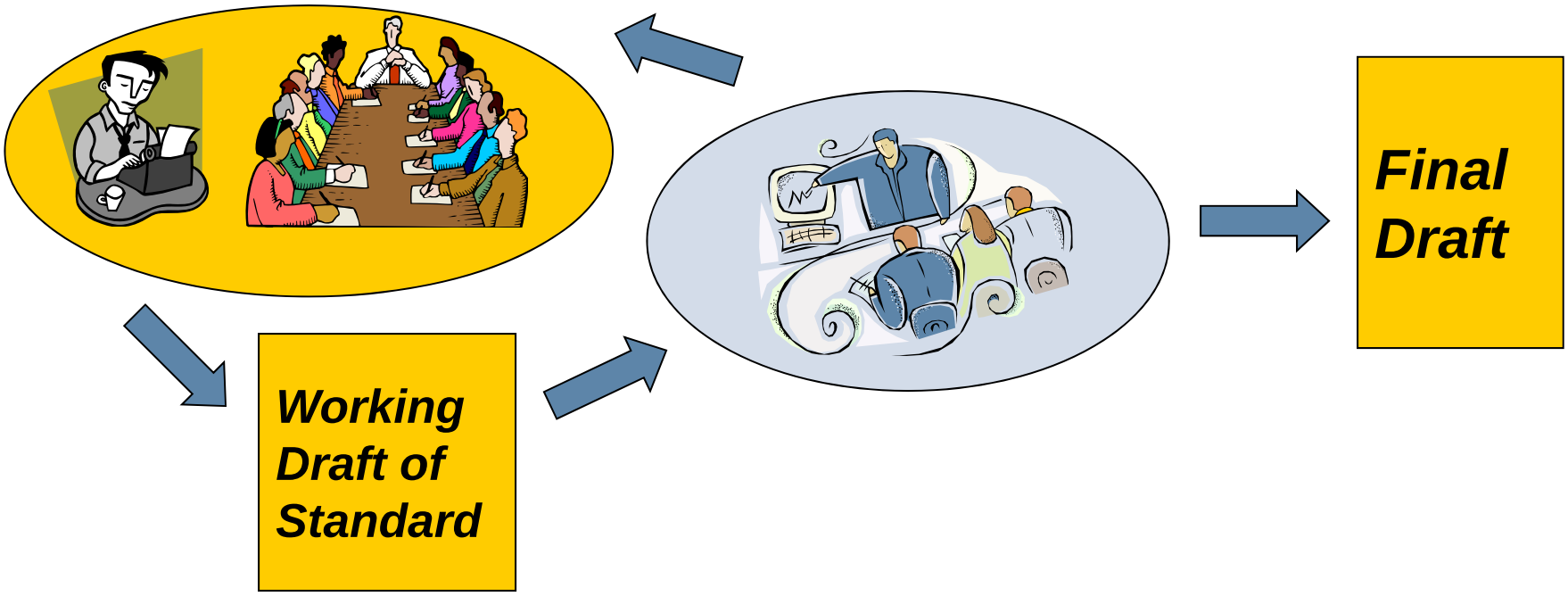
Recent standards initiatives

- Definition of Bulk Electric System
- Standards Development Prioritization (round two)
- Coordinating the regional standards development programs
- Enforcement date reporting (US only)
- Standards Process Changes
  - Rapid Development (standards)
  - Rapid Revision (interpretations)
- Quality Review Process

Emphasis on Quality

Industry based quality review required before "final" draft is posted

Results of the industry review are sent to the Standards Committee and drafting team



Standards in Effect

- As of November 15, 2011, NERC has 124 continent wide and regional standards in effect
  - 116 are currently enforceable
  - 8 are subject to future enforcement
- An additional 49 standards have been approved by the NERC Board of Trustees, but are not yet approved by FERC

Upcoming Initiatives

- Establishing an annual assessment of reliability performance (~May 2012).
- Participation from industry leadership in determining the effectiveness of the standards development process and the options for change.
- Improving the understanding by industry of the purpose for existing NERC programs and practices
  - Compliance Application Notices (CANs)



Questions?

Herb Schrayshuen
herb.schrayshuen@nerc.com
315 439 1390

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2010-17 Definition of Bulk Electric System

NPCC General Meeting
November 30, 2011

Peter Heidrich, FRCC – BES Definition Drafting Team Chair
Ken Lotterhos, Navigant/NPCC – RoP Drafting Team Member

RELIABILITY | ACCOUNTABILITY



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Topics

- History
- Order Nos. 743 & 743A
- Revised Bulk Electric System (BES) Definition
- RoP Exception Process (Appendix 5C)
- Exception Application Form
- Implementation Plan
- Near-term Project Milestones
- Phased Project Plan

Current Bulk Electric System (BES) Definition

From the Glossary of Terms Used in NERC Reliability Standards:

Bulk Electric System (BES):

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

Order No. 693

Commission Determination:

"…for at least an initial period, the Commission will rely on the NERC definition of bulk electric system and NERC's registration process to provide as much certainty as possible regarding the applicability to and the responsibility of specific entities to comply with the Reliability Standards in the start-up phase of a mandatory Reliability Standard regime."

"The Commission intends to address this matter in a future proceeding."

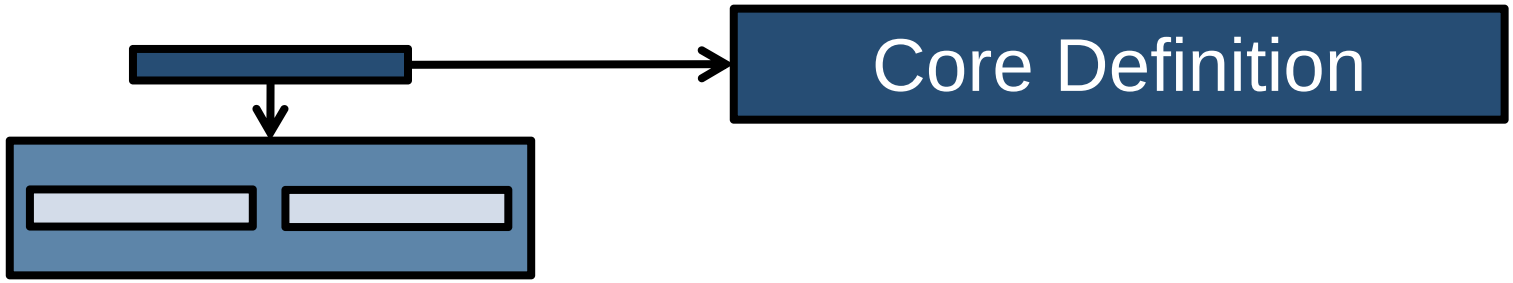
Orders No. 743 & 743-A

Directives from Orders No. 743 & 743-A:

1. Modify the Definition of Bulk Electric System
   - Eliminate “as defined by Regions” language
   - Eliminate “generally defined as” language
2. Develop an Exception Process
3. Develop Regional Transition Plans
4. Filing Due Date of January 25, 2012

(Addressed in Phase 1 of Project 2010-17)

Bulk Electric System Definition



Bulk Electric System (BES):

Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

BES Designation Criteria Inclusions



I1 - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3.

BES Designation Criteria Inclusions



I2 - Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above.

BES Designation Criteria Inclusions



I3 - Blackstart Resources identified in the Transmission Operator's restoration plan.

BES Designation Criteria Inclusions



I4 - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

BES Designation Criteria Inclusions



I5 –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

BES Designation Criteria Exclusions



E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

a) Only serves Load. Or,

b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

BES Designation Criteria Exclusions



E2 - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

BES Designation Criteria Exclusions



E3 - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system.

BES Designation Criteria Exclusions



E3 - The LN is characterized by all of the following:

a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

BES Designation Criteria Exclusions



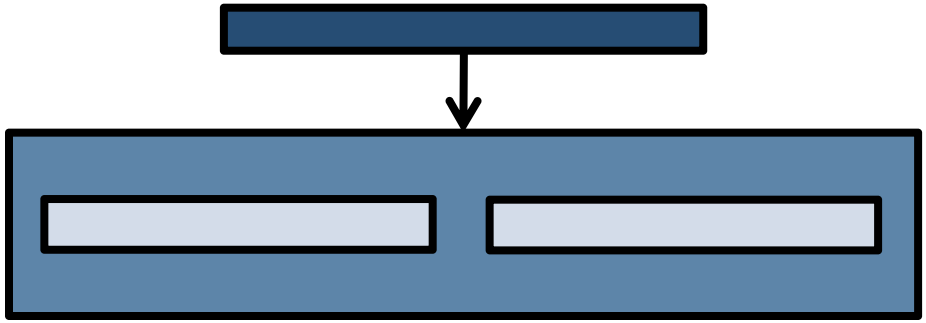
c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

BES Designation Criteria Exclusions



E4 – Reactive Power devices owned and operated by the retail customer solely for it's own use.

Bulk Electric System Definition



Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Rules of Procedure Exception Process

- What has been posted (Through October 27, 2011)
  - For Comment
    - New Rule 509
    - New Rule 1703
    - New Appendix 5C
  - For information
    - Process flow diagrams
    - Exception Request Form (Sample)

Rules of Procedure Exception Process

- New Rule 509 - Exceptions to the Definition of the Bulk Electric System

"*An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES definition to the Element (including the inclusions and exclusions set forth therein).* Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered a part of the Bulk Electric System."

Rules of Procedure Exception Process

- New Appendix 5C
  - Entity determination of status is a prerequisite for requesting an exception.
- Section 4: Who's and What's
  - Who can submit and who to submit a request to
  - What to submit
  - Who "approves"
  - What happens if I disagree

Rules of Procedure Exception Process

- Section 5: Initial Screening
  - Region “accepts or rejects” the request for substantive review
    - Eligible submitter?
    - Request for Exception?
    - Required Information provided?

Rules of Procedure Exception Process

- Section 5: Substantive Review
  - Region recommends “Approval or Disapproval” of request to NERC based on:
    - “…necessary for the reliable operation of the interconnected bulk power transmission system as evidenced by Required Information provided”.
    - Section 215(a)(4) defines reliable operation.

Rules of Procedure Exception Process

- Section 8: NERC Decision
  - NERC receives the request record with a recommendation from the Regional Entity
    - States the basis for the recommendation
    - Includes information considered by the RE in arriving at its Recommendation
  - Submitting Entity or Owner has opportunity to comment in support or opposition to the recommendation
  - NERC decision final if not appealed

Rules of Procedure Exception Process

- New Rule 1703 - Challenges to NERC Determinations of BES Exception Requests under ROP
  - Leverages existing (proposed) appeals process
  - NERC's decision to Approve, Disapprove, or Terminate
  - 30 days to appeal
  - 90 days for review panel to decide
  - May request BOTCC review panel decision

Rules of Procedure Exception Process

- Implementation Plans for Requests (Section 10)
  - Status “as is” when going through the process
  - Some implementation may be necessary for:
    - New Inclusion Exceptions
    - Denials of Exception Requests for Exclusion
      - newly-constructed or installed Element
      - was not included in the BES under the BES Definition in effect

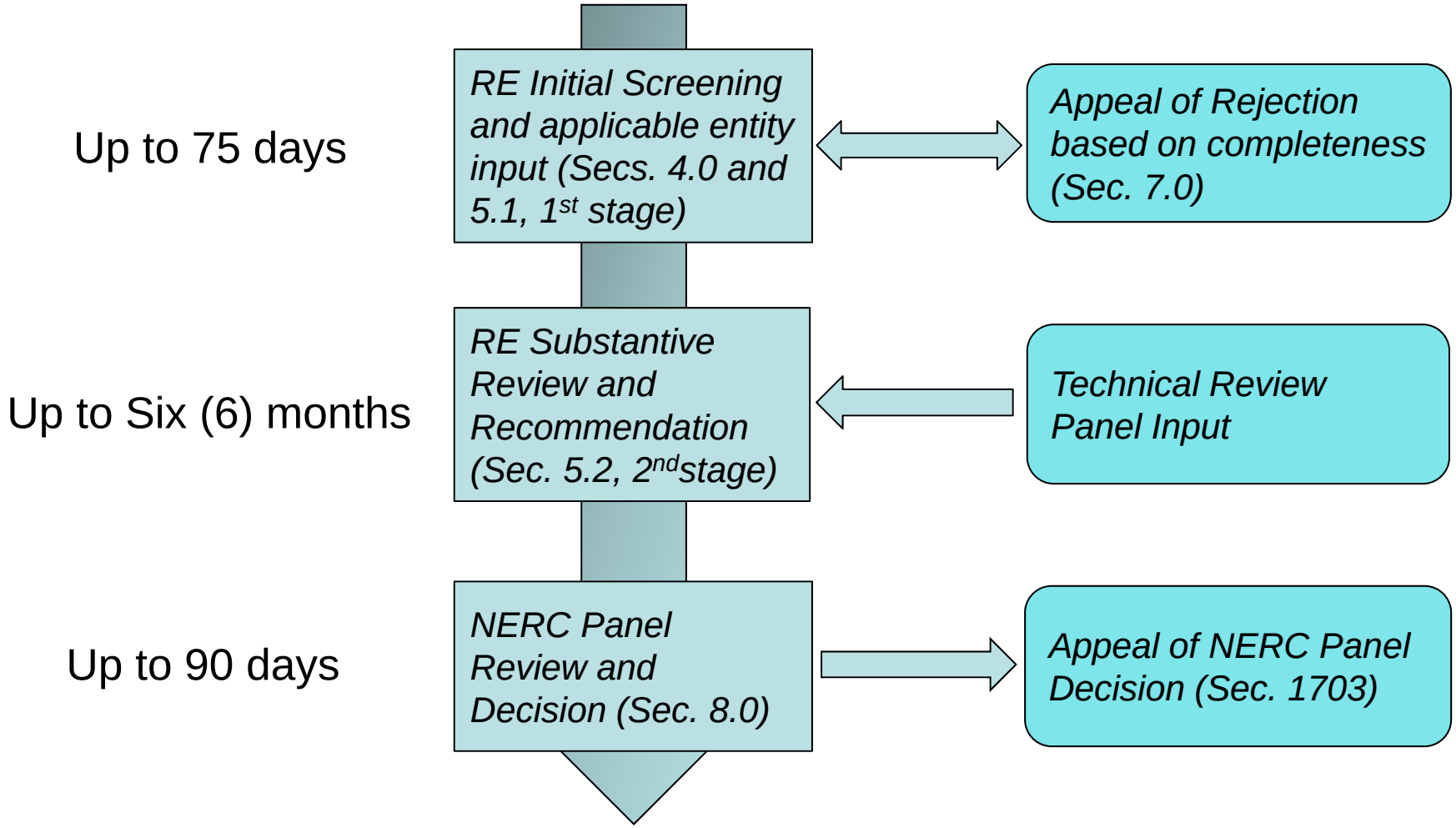
Rules of Procedure Exception Process

- Second Round Comments Concerning Process Complexity

  The RoP team believes the proposed process balances the need for effective and efficient reliability administration with due process and clarity of expectations.

Rules of Procedure Exception Process

Exception Request Submission



Rules of Procedure Exception Process

- Some Other Second Round Comments Addressed
  - Coordination with non-U.S. Entities
  - Regional Entity Exception Request Process
  - Appointment of Regional Entity Technical Review Panel and NERC Review Panel
  - Access to Data for Supporting an Exception Request
  - NERC Review Panel Decisional Transparency
  - Appeal time under section 1703

Rules of Procedure Exception Process

Next Steps

- Completion of changes responding to the second set of comments to the Exception Process Rules of Procedure.
- Presentation to the NERC Board of trustees for approval at the same time as the BES definition.
- Filing with FERC to meet the regulatory deadlines in FERC Orders 743 and 743A by January 25, 2012.

Exception Process Technical Principles

- Reliability benefits of an Element cannot be determined by a single study or analysis of a single parameter.
- Not feasible to establish continent-wide values and/or limits.

Exception Process Technical Principles

- The SDT has adopted a ‘big picture’ approach:
  - ‘Detailed Information to Support an Exception Request’ Application Form
  - Targeted questions for Transmission and Generation addressing the facility characteristics with guidance on the type of supporting evidence to accompany request.
  - No hard numbers to guide the evaluation.
  - Engineering judgment will be utilized to perform the evaluation of the evidence in a consistent, repeatable, and verifiable process.

Application Form - General Instructions

- Entities are required to provide:
  - A one-line breaker diagram identifying the Elements and the Protection Systems at the interface points for which the exception is requested.
  - The data and studies needed to support their submittal. Studies should:
    1. Be based on an Interconnection-wide base case
    2. Clearly document all assumptions used
    3. Address key performance measures of BES reliability through steady-state power flow and transient stability analysis
  - Support for your position from other entities (if available).

Application Form - For Transmission Elements

1. Is there generation connected to the Elements?
2. How does the Element(s) impact permanent Flowgates in the Eastern Interconnection, major transfer paths within the Western Interconnection, or a comparable monitored facility in the ERCOT Interconnection or the Quebec Interconnection?
3. Is the Element(s) included in an IROL in the Eastern Interconnection, ERCOT Interconnection, or Quebec Interconnection or a major transfer path rating in the Western Interconnection?
4. How does an outage of the Element(s) impact the over-all reliability of the BES?

Application Form - For Transmission Facilities

5. Is the Element(s) used for off-site power supply to a nuclear power plant as designated in a mutually agreed upon Nuclear Plant Interface Requirement (NPIR)?
6. Is the Element(s) part of a Cranking Path identified in a Transmission Operator's restoration plan?
7. Does power flow through this Element(s) into the BES?

Application Form - For Generation Resources

1. What is the MW value of the host Balancing Authority's most severe single Contingency and what is the generation resource's percent of this value?
2. Is the generation resource used to provide reliability related Ancillary Services?
3. Is the generator designated as a must run unit for reliability?
4. How does an outage of the generation resource impact the over-all reliability of the BES?
5. Does the generation resource use the BES to deliver its actual or scheduled output, or a portion of its actual or scheduled output, to Load?

Exception Process Technical Principles

- Industry Concern:
  - Impact of ‘yes’ or ‘no’ response to questions

    Appendix 5C of the proposed NERC Rules of Procedure, Section 3.2 of the proposed Rules of Procedure that states “No single piece of evidence provided as part of an Exception Request or response to a question will be solely dispositive in the determination of whether an Exception Request shall be approved or disapproved.”

Implementation Plan

- **Effective Dates:**
  - This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval.
  - In those jurisdictions where no regulatory approval is required the definition shall go into effect on the first day of the second calendar quarter after Board of Trustees adoption.

Implementation Plan

- **Compliance Obligations:**
  - Compliance obligations for Elements included by the definition shall begin 24 months after the applicable effective date of the definition.
  - SDT believes that the timeframe is needed to:
    - Effectively produce reasonable transition plans
    - Submit any necessary registration changes
    - File for exceptions
    - Provide training

Near-term Project Milestones

- Special Meeting w/ NERC BOT (Jan. 18, 2012)
- File with the Commission (FERC) by Jan. 25, 2012

Project Plan - Phased Approach

- Why Two Phases?
  - A strong, factual, technical justification is **essential** if we are to gain FERC approval for any changes to things such as generator thresholds
  - Need time to run studies and produce technical justifications to support proposals
  - BES Definition due January 25, 2012

Project Plan - Phased Approach

- NERC Standards Committee
  - Approved the multi-phased approach
  - Committed to keeping this project on its “High Priority” project list
  - Committed to continuing development work with the current SDT through completion of Phase 2
  - Committed to supplying resources to complete technical research

Project Plan - Phased Approach

Phase 2 - Addresses concerns identified through the Standards Development Process:

1. Reliability benefit of a contiguous BES
2. 100 kV bright-line voltage threshold
3. 'Points of Demarcation' between Transmission, Generation, and Distribution
4. Threshold for Generation Resources

Project Plan - Phased Approach

Phase 2 - Addresses concerns identified through the Standards Development Process:

5. Scope of the equipment which supports the reliable operation of the BES
6. Relationship between the BES definition and the ERO Statement of Compliance Registry Criteria
7. Analysis of the application of, and the results from, the Exception Process

Project Plan - Phased Approach

- DRAFT Standard Authorization Request
  - Establishes Phase 2 of the project
  - Posted for informational purposes ONLY
  - Will be posted for comment later in the project

Project Plan - Phased Approach

- Additional Information
  - Bulk Electric System Definition Project - Fact Sheet

http://www.nerc.com/docs/standards/sar/BES_Definition_Fact_Sheet_20110920_final.pdf



Question & Answer

Website: http://www.nerc.com/filez/standards/Project2010-17_BES.html

2011 Security and Compliance

Greg Goodrich, CISSP
Supervisor, Enterprise Security
New York Independent System Operator

NPCC General Meeting
November 30, 2011
Toronto, Ontario

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Agenda

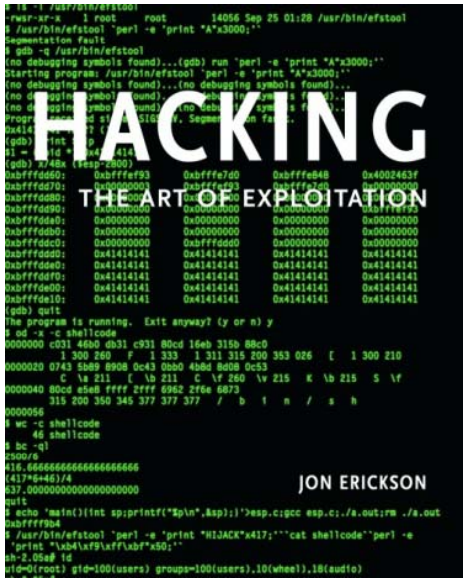
- **Security Trends**
  - ***Challenges , threats and trends***
- **Compliance and NERC CIP**
  - ***Challenges and trends***
  - ***CIP Versions 3, 4 and 5***



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Energy Sector Facing New Challenges

- **Security threats becoming more real and increasing**
- **Government increasing activity**
- **Compliance and oversight being sought**
- **Changes becoming more rapid**



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What if Blackberry Outage Was ICCP?

BlackBerry Four-Day Worldwide Outage

- Duration
- Recovery
- Customer Service
- Reputation & Stocks



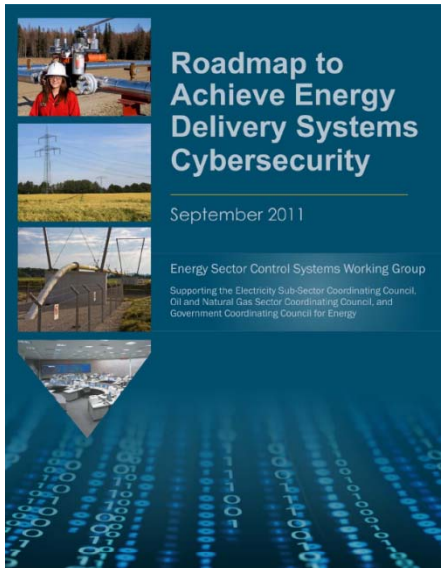
NERC GridEx 2011

- Malware spreading via ICCP
- 2011 was an opportunity for NERC, industry stakeholders and government partners to work together

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Energy Sector Key Challenges

- **Cyber threats are unpredictable and evolve faster than the sector's ability to develop and deploy countermeasures**
- **Security upgrades to legacy systems is limited by the inherent limitations of the equipment and architectures**
- **Performance/acceptance testing of new control and communication solutions is difficult without disrupting operations**
- **Threat, vulnerability, incident, and mitigation information sharing is insufficient among government and industry**
- **Weak business case for cyber security investment by industry**
- **Source: https://www.controlsystemsroadmap.net/ieRoadmap%20Documents/roadmap.pdf**



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Security and Compliance

- **Compliance should be the floor you land on when your security is tripped**

- **Defense In Depth**
  - ***Security***
  - ***Compliance***



Compliance….

http://www.clipartpal.com/_thumbs/man_012001575_tnb.png

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Challenges: Information sharing

- **Business requires information sharing requiring cyber interconnections increasing cyber risks**
  - ***SCADA/EMS/BMS***
  - ***Smart Grid***
  - ***Markets***
  - ***Corporate***
  - ***Customers***
  - ***Planning***



http://www.texaspowerblog.com/wp-content/uploads/2011/06/smart-meter-oncor-tx01.jpg

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Challenges: Financial

- **Budgets cycles**
  - ***18 months minimum to implement changes without impacting other commitments***
  - ***3-5 year planning cycles***
- **Customers costs increase**
- **Regulators – Who pays?**



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Challenges: Workforce

- **Targeted threats toward workforce**
  - ***Surveillance of each company***
  - ***Attempt to target staff and customers***
- **Social Engineering and Media**
  - ***Educating and keeping workforce cyber safe while progressing with technology and social media***
    - **Linkedin**
    - **Facebook**



http://www.macforensicslab.com/ProductsAndServices/images/whitepaper-image021.png

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Challenges: Cyber Terrorism

- **Cyber terrorism is a rapidly growing threat per FBI director Robert Mueller – March 2010**
- **FBI says Anonymous is a potential threat to national security**
- **Sources for cyber terrorism**
  - ***Nation States***
  - ***Organized crime***
  - ***Hactivisum - organized special interest***



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Challenges: Threats ICS/SCADA

- **Stuxnet**
  - ***Different from previous malware in its sophistication, single-minded purpose, and ability to manipulate and damage real-world physical equipment.***
- **Night Dragon – Vendor challenges:**
  - ***Vendor X definitions October 2010***
  - ***Vendor Y releases details February 2011***
- **Exploits available to the public as "how to" or kits**

  - ***Increase of presentations on Industrial Control Systems (ICS) and Supervisory Control And Data Acquisition (SCADA) at DefCon and Blackhat in 2011***

  - ***Six SCADA presentations planned at Hacker Halted USA conference - October 2011***

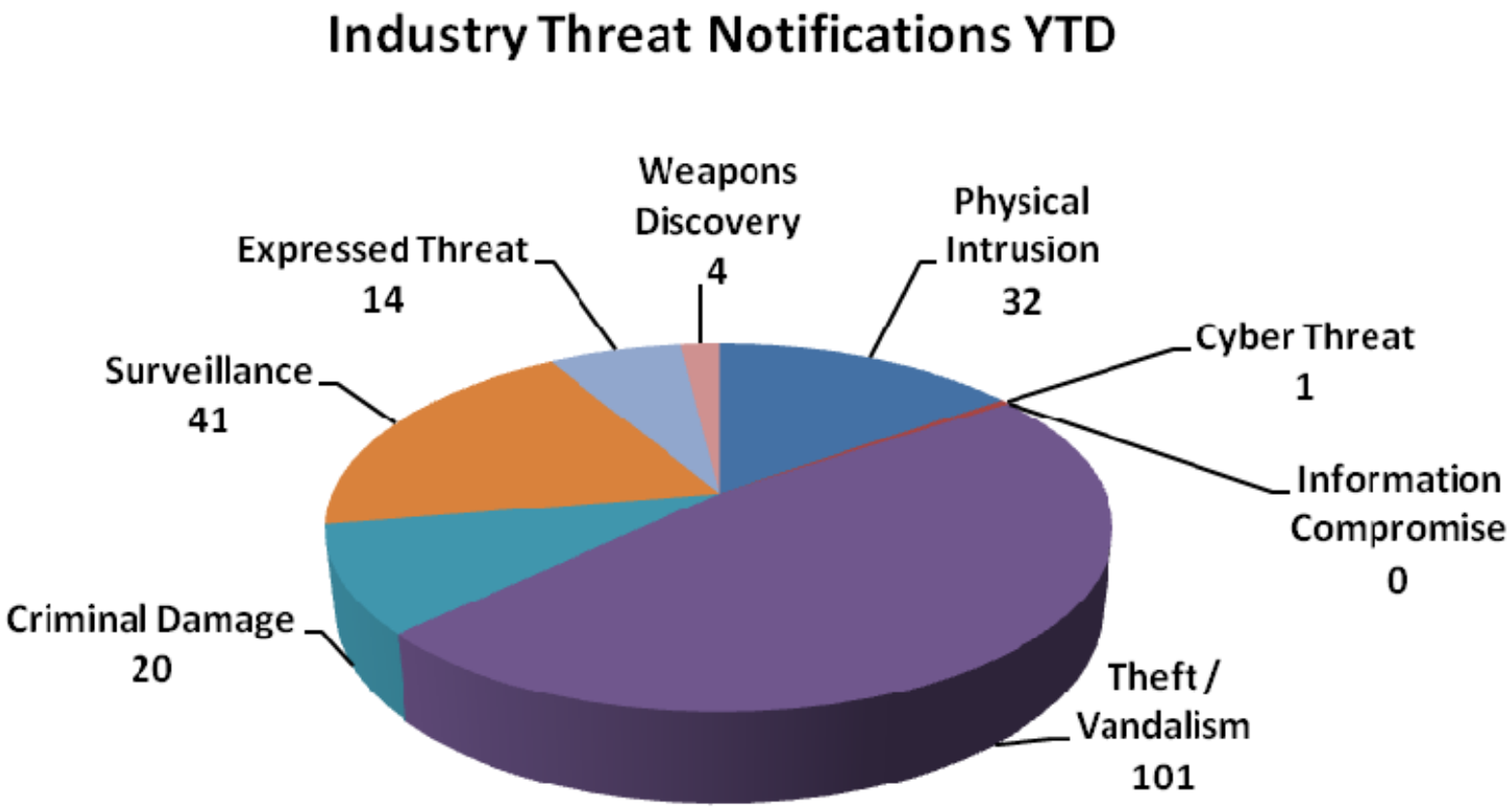
  - ***Information is being documented and "hacker" kits made for ICS and SCADA equipment***



http://www.spywarefixpro.com/wp-content/uploads/2010/10/iran_stuxnet.jpg

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Industry Threat Notifications



SOURCE: NYISO Enterprise Security Dashboard

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Breaking News!

- **Son of Stuxnet Found in the Wild on Systems in Europe "Duqu"**



- **Industry Warnings:**
  - ***NERC Alert – Targeted Spear Phishing***
  - ***ICS-Cert – Alter on key logger & Cert compromise***

- **What really happened in Illinois to the water pump?**



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Challenges – Cyber Industry

- **Evolving cyber security from response to prevention focus**
  - ***Treatment***
    - **Treat symptoms - After infection**
    - **Detection of virus signature**
    - **Antivirus – Detect – Quarantine/Remove**
  - ***Prevention***
    - **Screen early and often - Before spread**
    - **Pre-emptive - Before install**
    - **Changes to patterns in SCADA/ICS**
    - **Proxy - Screen emails and traffic inbound**



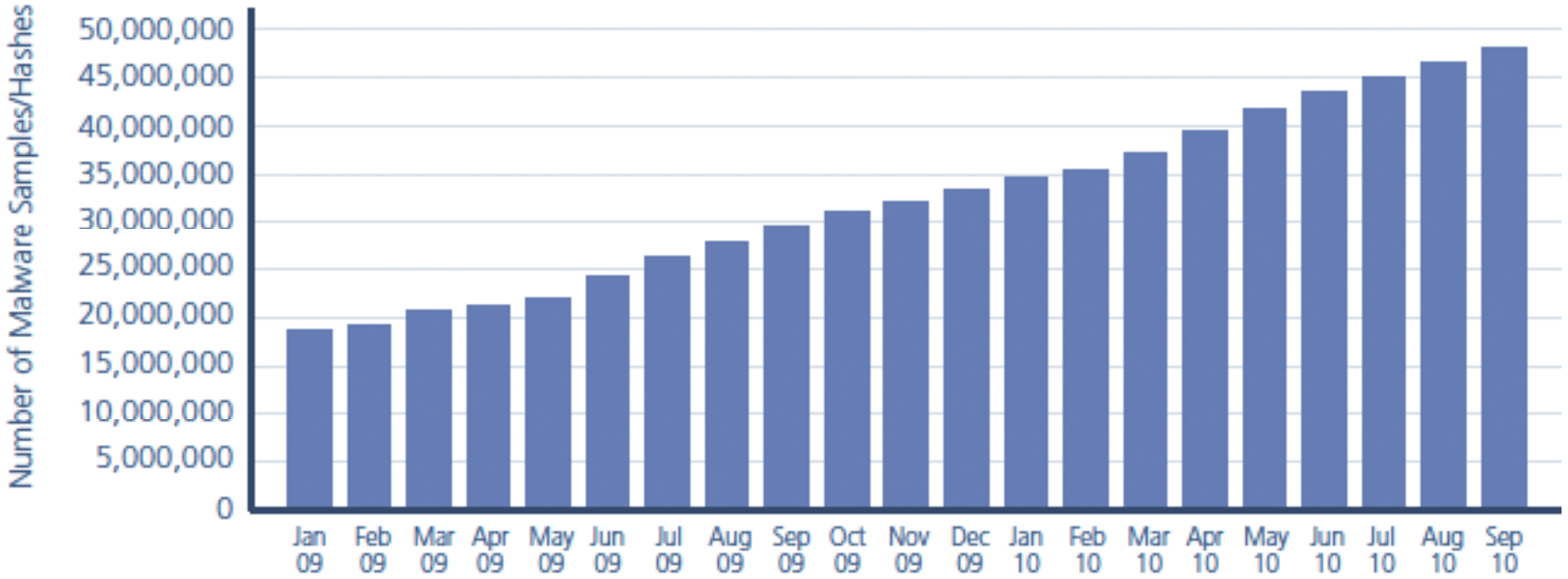


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Cyber Security

Average Daily Malware at All Time High

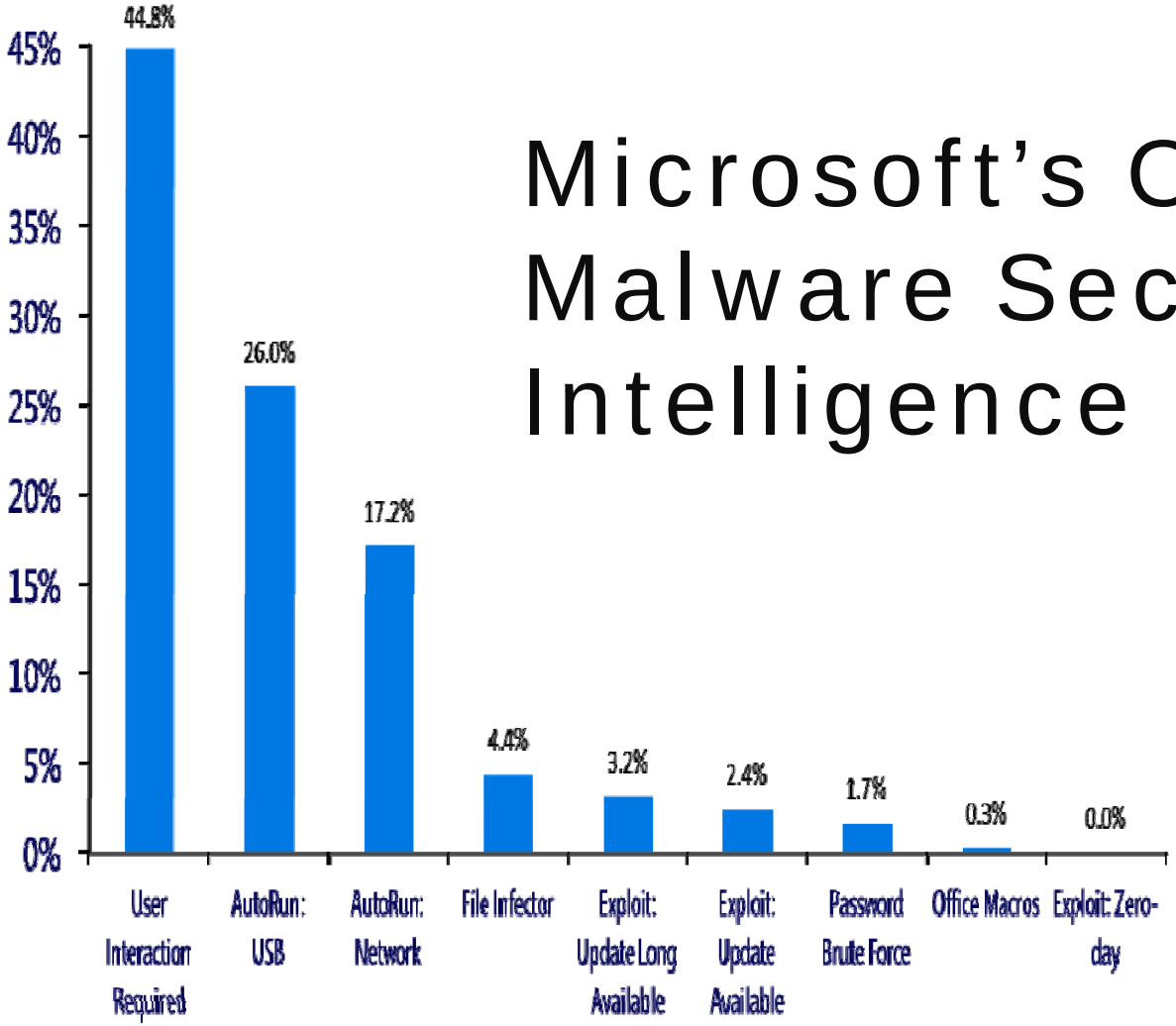
-- McAfee 2010 Report



Source: McAfee

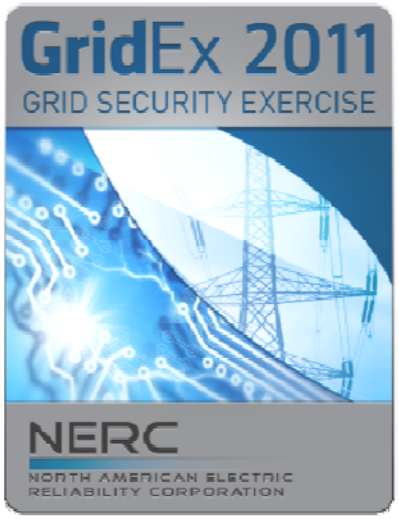
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Microsoft's October Malware Security Intelligence Report



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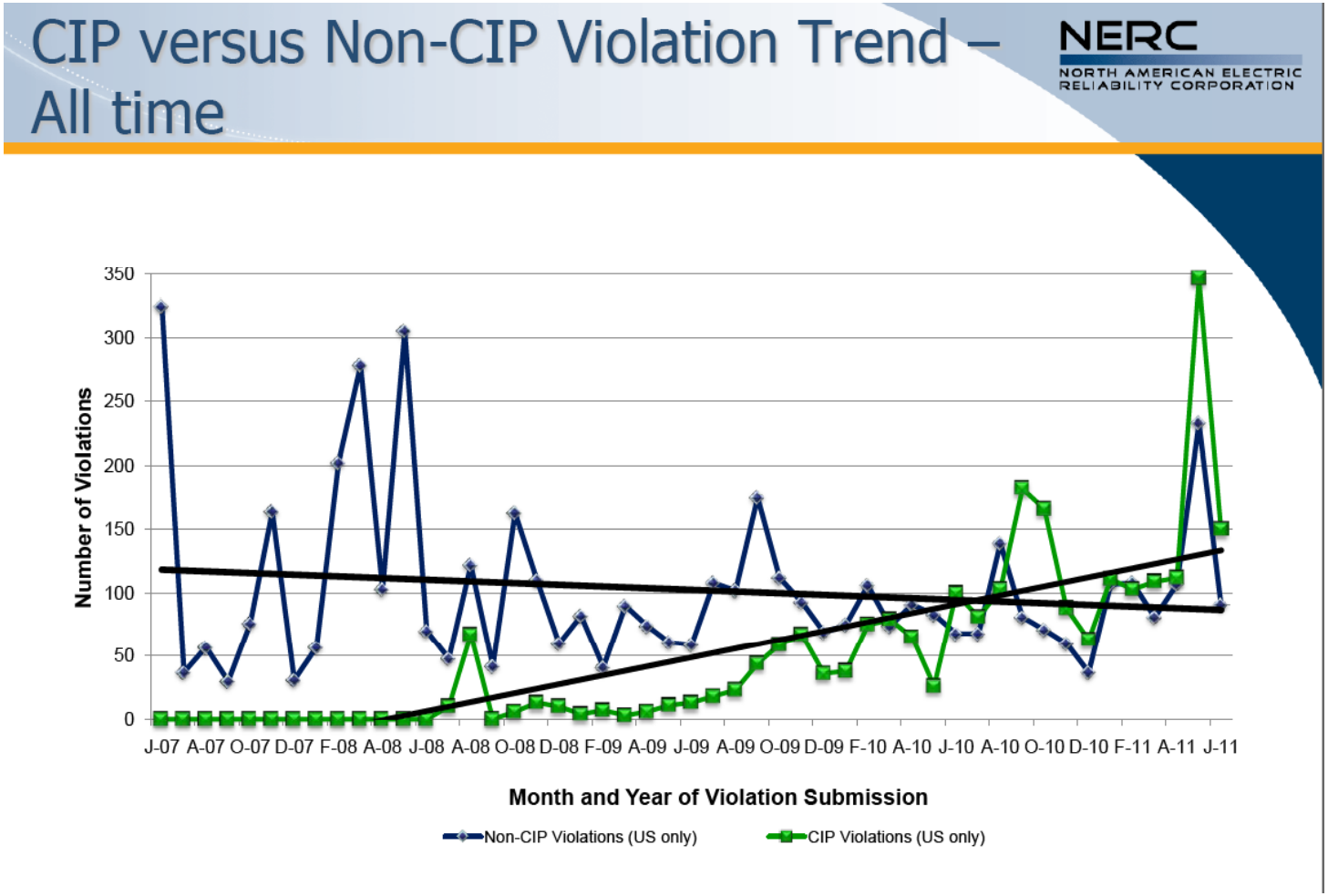
Industry Response to Challenges



- **Education and awareness**
  - ***Webinars***
  - ***NERC GridEx Exercise***
  - ***GRID Security Conference***
- **Smart Grid Security**
- **NERC Critical Infrastructure Protection**
  - ***Stepped up enforcement***
  - ***New versions of CIP***

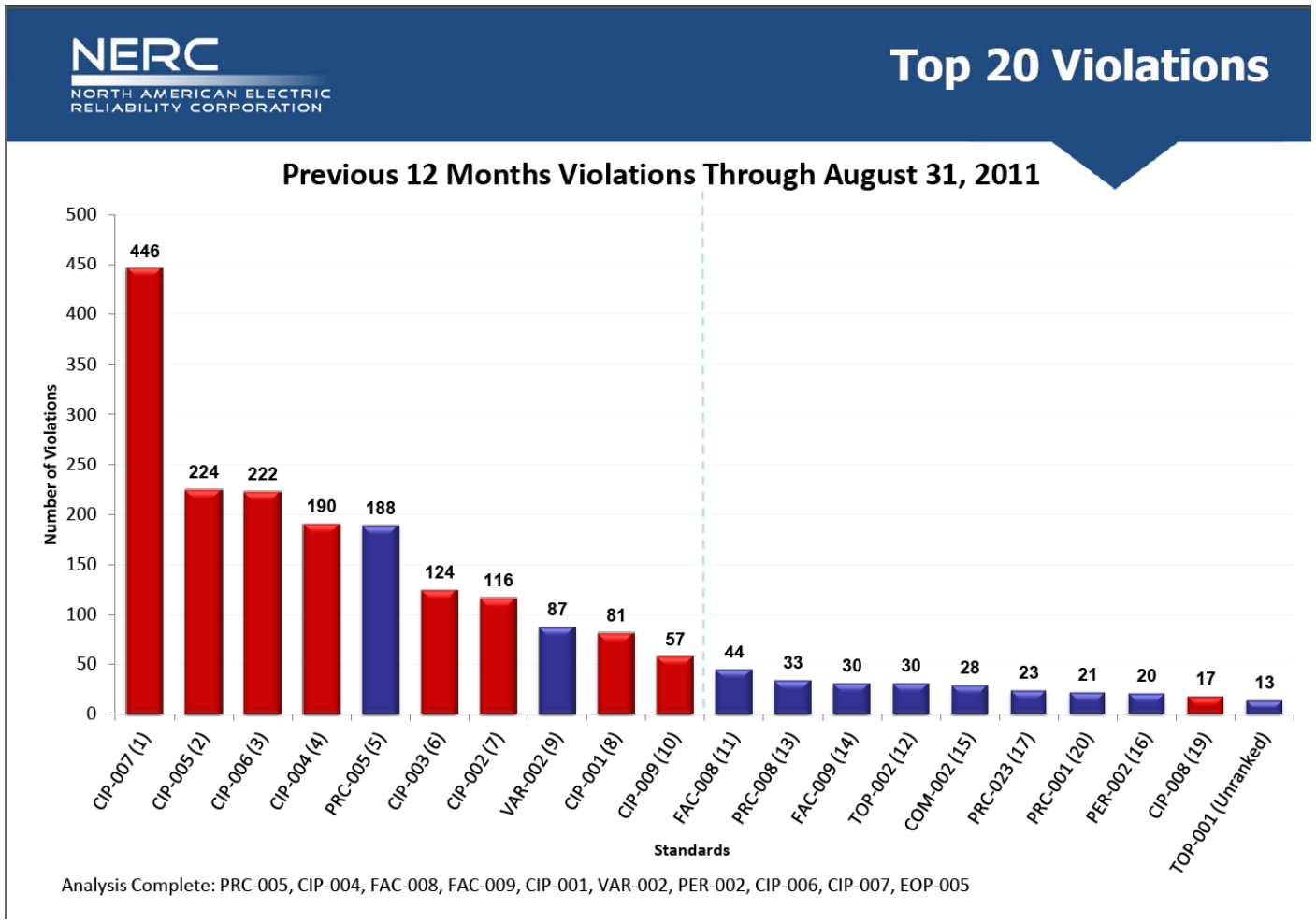
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CIP Violation Trends



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CIP Enforcement Increasing



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NERC CIP Version 3/4 & 5

CIP Version 3/4

- *CIP-002 Critical Cyber Asset Identification*
- *CIP-003 Security Management Controls*
- *CIP-004 Personnel and Training*
- *CIP-005 Electronic Security Perimeter(s)*
- *CIP-006 Physical Security of Critical Cyber Assets*
- *CIP-007 Systems Security Management*
- *CIP-008 Incident Reporting and Response Planning*
- *CIP-009 Recovery Plans for Critical Cyber Assets*

CIP Version 5

- *CIP-002 BES Cyber Asset and BES Cyber System*
- *CIP-003 Security Management Controls*
- *CIP-004 Personnel and Training*
- *CIP-005 Electronic Security Perimeter(s)*
- *CIP-006 Physical Security of BES Cyber Systems*
- *CIP-007 Systems Security Management*
- *CIP-008 Incident Reporting and Response Planning*
- *CIP-009 Recovery Plans for BES Cyber Assets and Systems*
- *CIP-010 Configuration Management and Vulnerability Assessments*
- *CIP-011 Information Protection*

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CIP Version 5 – Highlights

- **New definitions**
- **Mapping document**
- **Updated Format**
  - ***Rationale – Purpose of requirement and any assumptions made about the requirement***
  - ***Summary of Changes – High level overview of changes in this requirement***
  - ***Guidance – Additional guidance in applying the requirement***
  - ***Measurement***
- **Measurement acceptable evidence - procedures associated with the requirement**
- **Levels of Impact**
- **BES Systems**
- **Policy Changes**
- **Access Controls**
- **Ports and Services**
- **Change and Vulnerability CIP-010**
- **Information Sanitization CIP-011**

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Definitions

- **BES Reliability Operating Services**

  BES Reliability Operating Services are those services contributing to the real-time reliable operation of the Bulk Electric System (BES). They include the following Operating Services:…

- **BES Cyber Asset**

  A Cyber Asset that if rendered unavailable, degraded, or misused could, within 15 minutes cause a Disturbance to the BES and adversely impact one or more BES Reliability Operating Services.

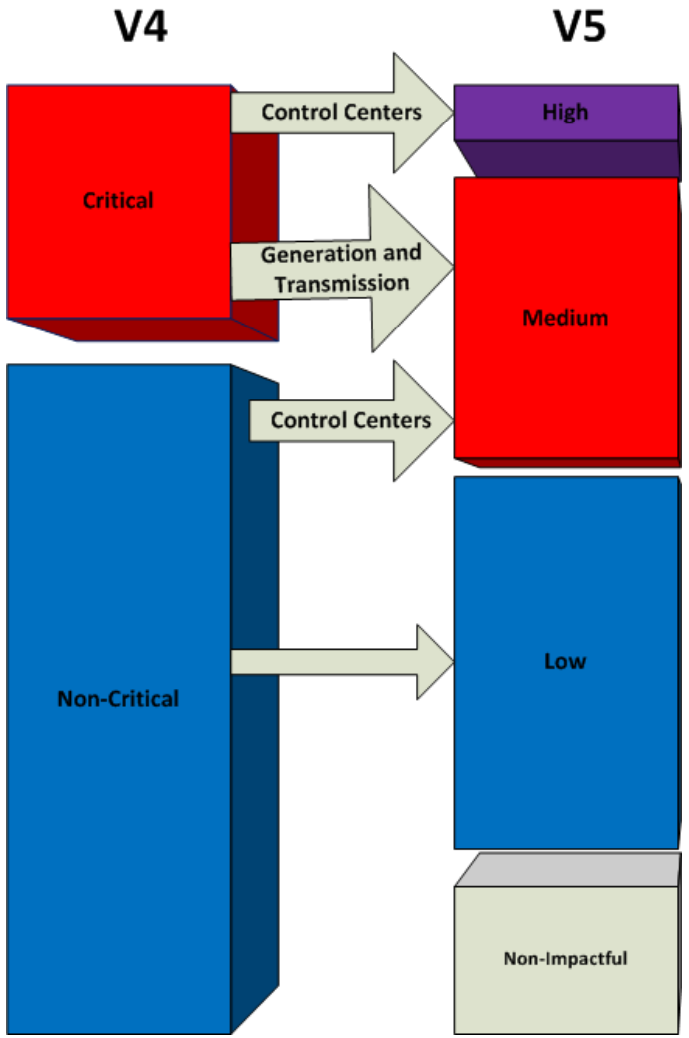
- **BES Cyber Systems**

  One or more BES Cyber Assets grouped together for the application of common cyber security controls. These are typically grouped together, logically or physically, to operate one or more BES Reliability Operating Services.

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Levels of Impact

- **High Impact**
  - ***Large Control Centers***
  - ***CIP-003 through 009+***
- **Medium Impact**
  - ***Generation and Transmission***
  - ***Other Control Centers***
  - ***Similar to CIP-003 to 009 v4***
- **All other BES Cyber Systems**
  - ***Security Policy***
  - ***Security Awareness***
  - ***Incident Response***
  - ***Boundary Protection***



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CIP V5 Ports and Services Solutions from drafting team

- **Acceptable ways to disable or restrict access:**
  - ***Logically Disable***
    - **Configuration**
  - ***Restrict***
    - **USB Lock**
  - ***Permanently Disable***
    - **Epoxy Glue**

```
!
interface Management0/0
 shutdown
 no nameif
 security-level 100
 ip address 10.1.0.24 255.255.0.0
 management-only
!
```





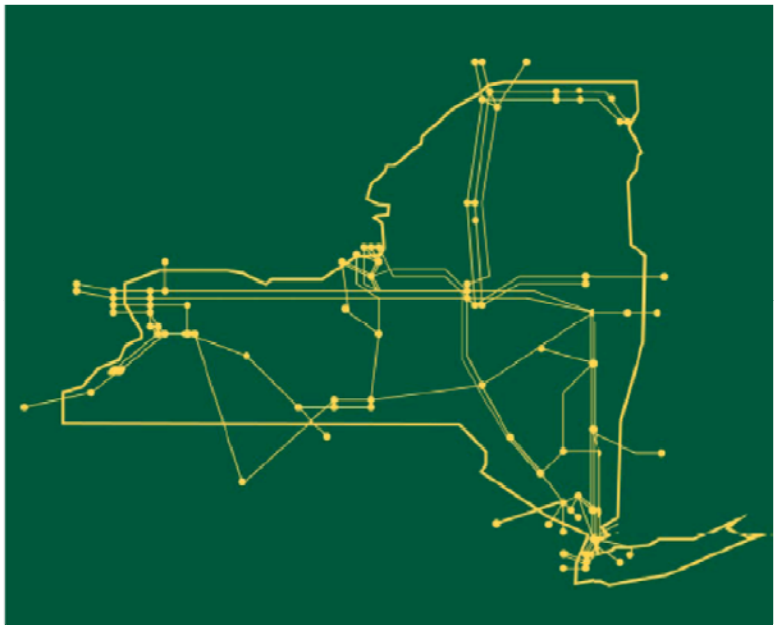
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Wrap Up

- **Security threats are increasing and changing**
- **Security, IT, Compliance, Regulatory, Legal and HR must work together to support the evolution of security and CIP**
- **CIP migration plans from version 3 to 4 then to 5 are not finalized but will have impact upon the industry**
- **Criteria for Assets and BES requires careful consideration at each entity**
  - ***Changes from asset to systems in CIP 5 – BES systems***
  - ***Policies***
  - ***Access Controls***
  - ***Change management and vulnerabilities***
  - ***Information protection***
- **The industry continues to demonstrate competencies with keeping the lights on**

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The New York Independent System Operator (NYISO) is a not-for-profit corporation responsible for operating the state's bulk electricity grid, administering New York's competitive wholesale electricity markets, conducting comprehensive long-term planning for the state's electric power system, and advancing the technological infrastructure of the electric system serving the Empire State.



www.nyiso.com

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ieso
Power to Ontario.
On Demand.

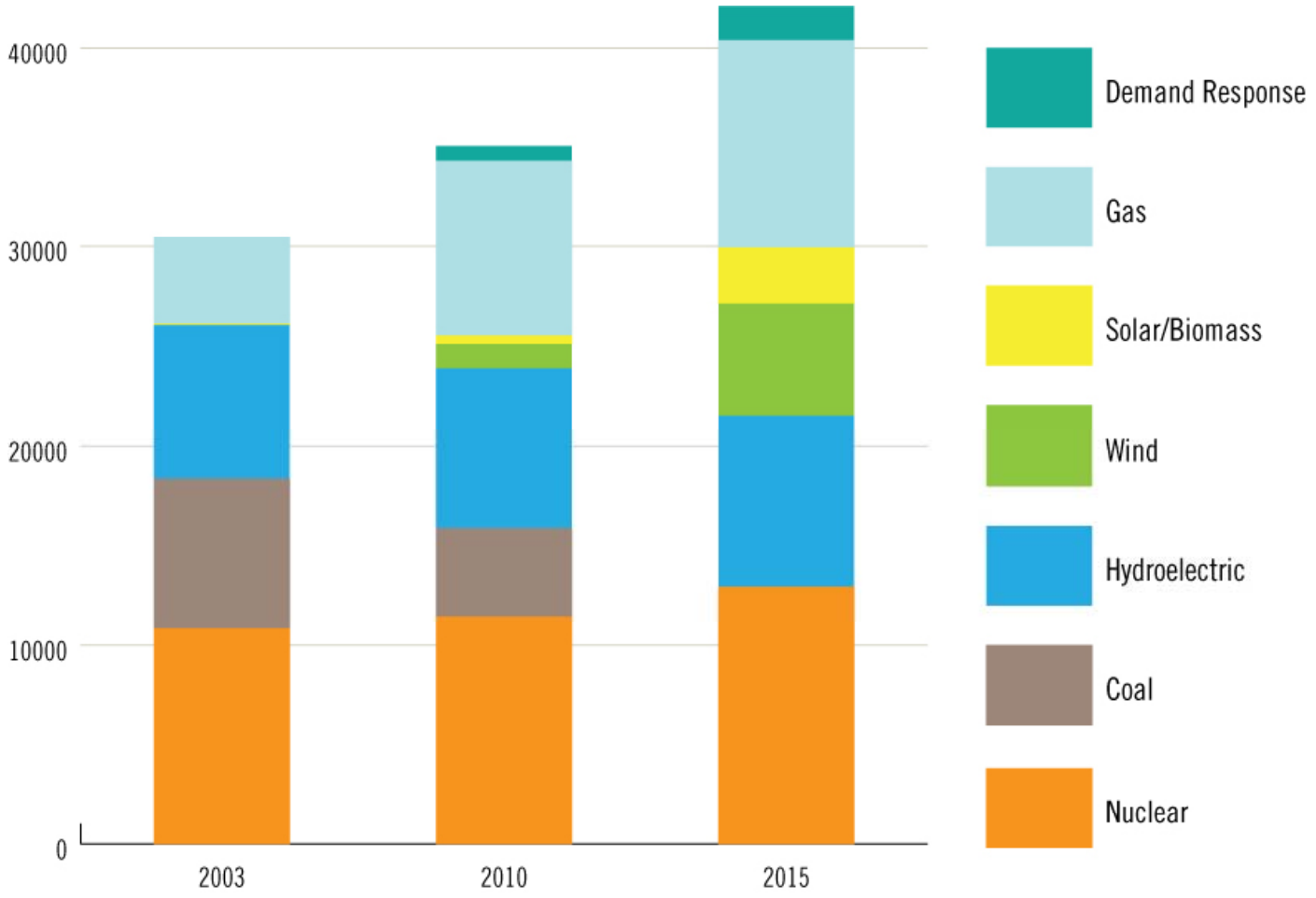
The Transformation of Ontario's Electricity Sector

Paul Murphy

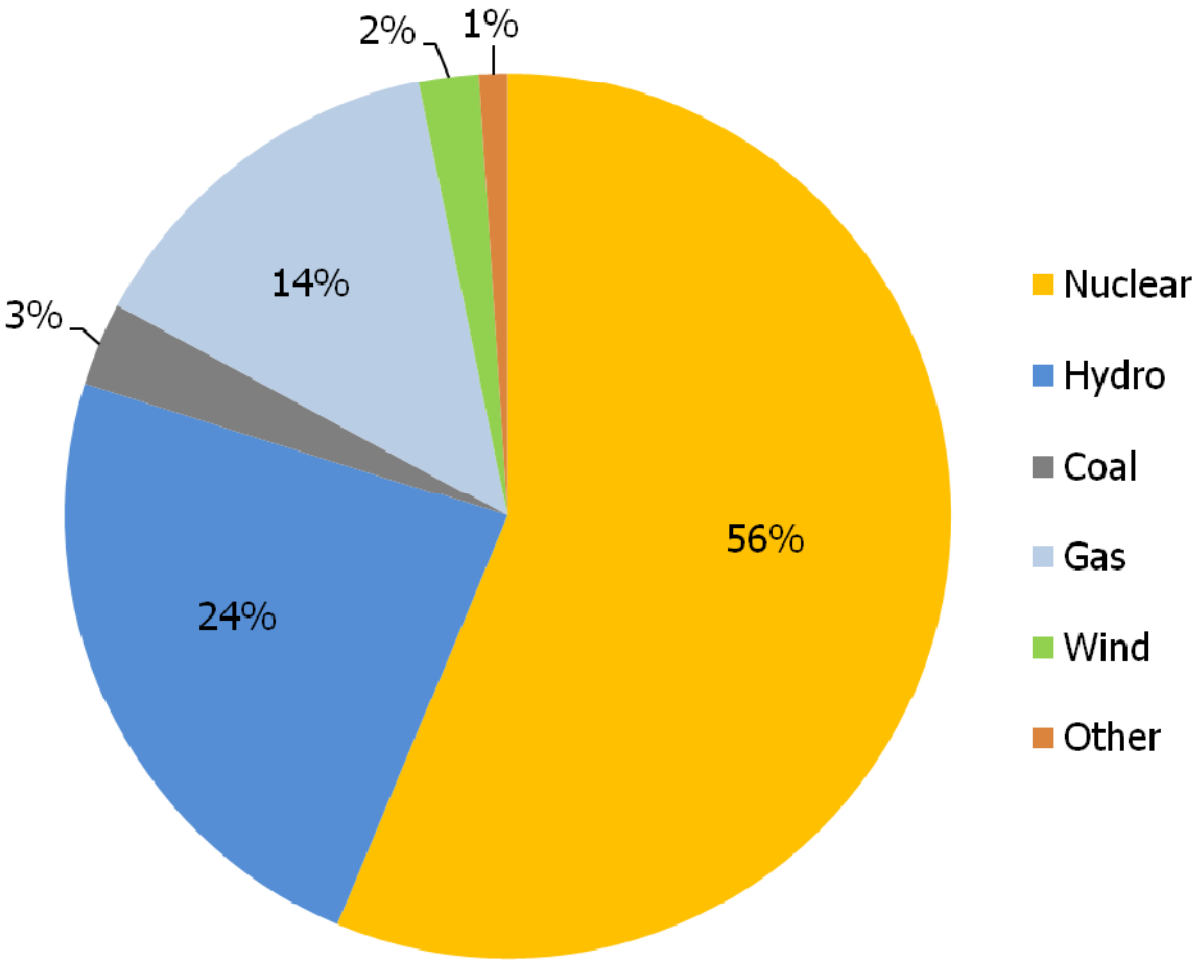




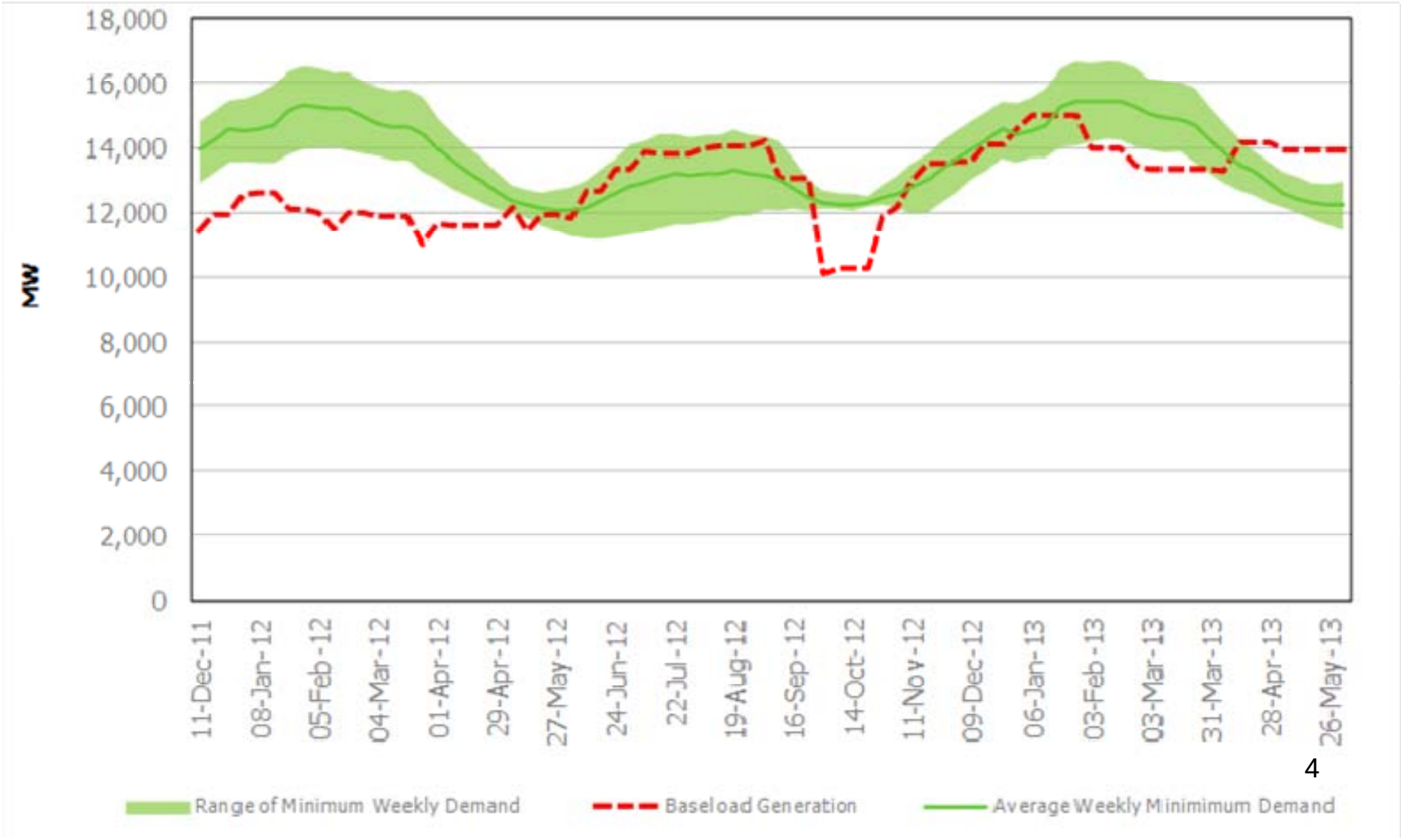
Installed Capacity



2011 Generation by Fuel Type (year-to-date)



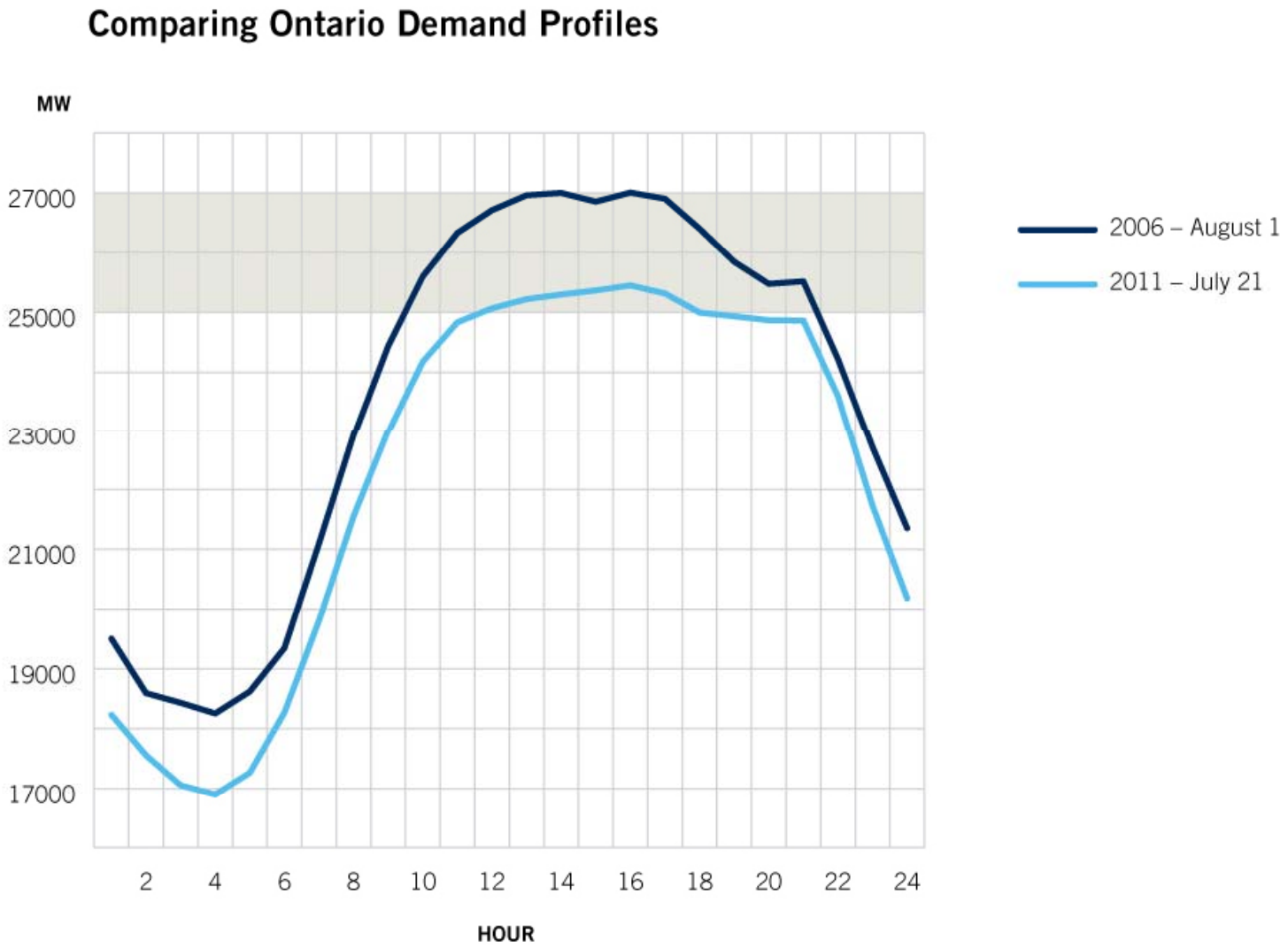
Surplus Baseload Generation



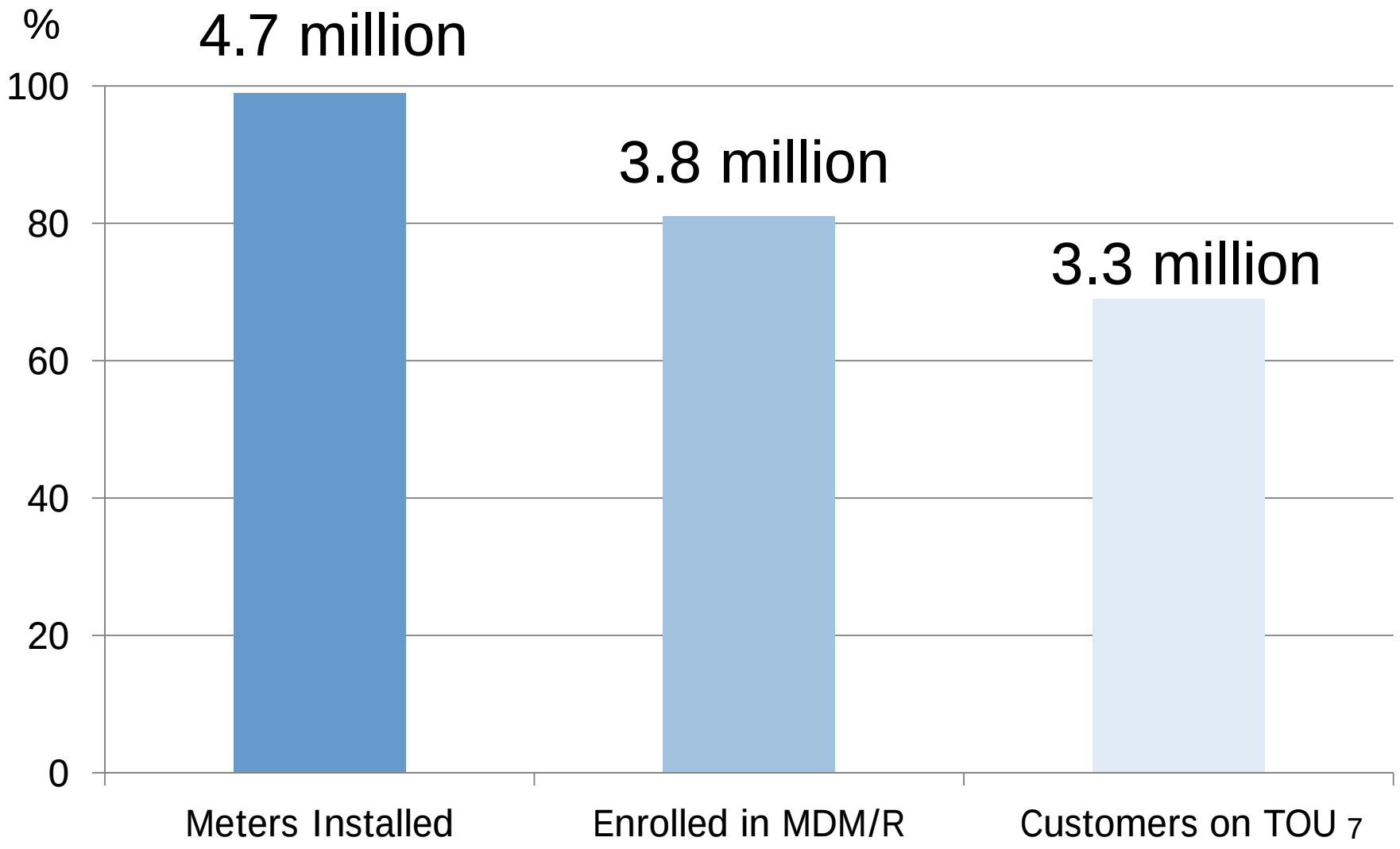
Ontario's Interties



Consumer Action Matters



Smart Metering Progress
(as of Sept 2011)



2012 NPCC General Meeting



Hotel Omni Mont-Royal

Montreal, Quebec

Wednesday, November 28, 2012



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

Northeast Power Coordinating Council

Reliability Assessment

For

Winter 2011-12

Conducted by the

NPCC CO-12 & CP-8 Working Groups

Final Report

Approved by the Reliability Coordinating Committee
November 29, 2011

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The information in this report is provided by the CO-12 Operations Planning Working Group of the NPCC Task Force on Coordination of Operation. Additional information provided by Reliability Councils adjacent to NPCC.

The CO-12 Working Group members are:

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Griselda Matos	Independent Electricity System Operator
Paul Metsa	TransÉnergie
Dragan Pecurica	Nova Scotia Power Inc.
Paul Roman	Northeast Power Coordinating Council
Helve Saarela	ISO New England
Kyle Ardolino	New York ISO

Information from neighboring Reliability Councils provided by:

Jeff Mitchell	Reliability First (RFC)
Paul Kure	Reliability First (RFC)

The Multi-Area Probabilistic Reliability Assessment provided in this report is provided by the CP-8 Working Group of the NPCC Task Force on Coordination of Planning.

The CP-8 Working Group members are:

Phil Fedora (Chair)	Northeast Power Coordinating Council
Alan Adamson	New York State Reliability Council
Rob Vance	New Brunswick System Operator
Frank Ciani	New York Independent System Operator
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J. W. (Jack) Martin	National Grid USA
Abdelhakim Sennoun	Hydro-Québec Distribution
Kamala Rangaswamy	Nova Scotia Power Inc.
Vithy Vithyananthan	Independent Electricity System Operator
Fei Zeng	ISO New England

The CP-8 Working Group acknowledges the efforts of Messrs. Glenn Haringa, GE Energy, and Andrew Ford, the PJM Interconnection, for their assistance in this analysis

1. Executive Summary

This report is based on the work of the NPCC CO-12 Operations Planning Working Group and focuses on the assessment of reliability within NPCC for the 2011-12 Winter Operating Period. Portions of this report are based on work previously completed for the NPCC Reliability Assessment for the Winter 2010-11[1].

Moreover, the NPCC CP-8 Working Group provides a seasonal multi-area probabilistic reliability assessment. Results of this assessment are included as a chapter in this report and supporting documentation is provided in Appendix VIII.

Those aspects that the CO-12 Working Group has examined to determine the reliability and adequacy of NPCC for the winter of 2011-12 are discussed in detail in the specific report sections. The following *Summary of Findings* addresses the significant points of the report discussion. These findings are based on projections of electric demand requirements, available resources and transmission configurations. This report evaluates NPCC's and the associated Balancing Authority areas' ability to deal with the differing resource and transmission configurations within NPCC and the associated Balancing Authority areas' preparations to deal with the possible uncertainties identified in this report.

Summary of Findings

- The forecasted coincident peak demand for NPCC during the peak week (week beginning January 15, 2012)[2] is 111,821 MW, as compared to 110,958 MW forecasted during 2010-11 Winter peak week. The capacity outlook indicates a forecasted Net Margin for that week of 18,641 MW. This equates to a net margin of 16.6 percent in terms of the 111,821 MW forecasted peak demand. This week also has the minimum percentage of forecasted Net Margin available to NPCC.
- The largest forecasted NPCC Net Margin of 37.0 percent occurs during the week beginning March 25, 2012. The minimum NPCC net margin from last winter was 17.7 percent and this winter it is 15.0 percent.
- During the NPCC forecasted peak week, the forecasted net margin in terms of forecasted demand ranges from approximately 1.8 percent in Québec to 45.0 percent in New York.

[1] The NPCC Assessments can be downloaded from the NPCC website https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx .

[2] Load and Capacity Forecast Summaries for NPCC, IESO, ISO-NE, NYISO, HQ and the Maritimes are included in Appendix I.

- When comparing the peak week from last winter (Jan. 9, 2011) to this winter's expected peak week (Jan. 15, 2012) the NPCC installed capacity has increased by 847 MW. New England has increased by 324 MW, New York by 308 MW, Maritimes by 65 MW and Québec by 738 MW, while Ontario has decreased by 588 MW.
- No delays are forecasted for the commissioning of new resources. However, any delay should not materially impact the overall net margin projections for NPCC.
- The Point Lepreau Nuclear station (approximately 658 MW) is out for refurbishment and is not expected back this Winter Operating Period. It was originally scheduled to be completed October 2009 but has since been delayed. The latest in-service date released is September 2012. With this outage, the Maritimes Area projected net margin remains positive. If load is higher than normal or if resource outages are higher than projected, net margin for some weeks may become negative. That should not be a problem as the Feasible Transfer Capability from Québec and New England to the Maritimes Area totals around 1,300 MW.
- Phase angle regulators (PARs) are now installed on all four of the Michigan - Ontario interconnections. Only one is in-service and regulating. The other three remain idle until approval of the US Department of Energy is granted.
- New York - Ontario intertie PA301 is planned out of service December 5-16 for New York maintenance. At times during this maintenance work, the New York - Ontario interface will be operated to a 0 MW scheduling limit in both directions and the Michigan - Ontario interface will be operated to less than 50 percent of the normal scheduling limits.
- The Québec area's internal demand forecast for winter 2011-12 is 37,153 MW. Compared to winter 2010-11 installed capacity will have grown 487 MW by December 2011. Four new wind plants and one unit at Eastmain-1-A have been placed in service, whereas one unit at Tracy Fossil-fuel G.S. has been retired. In January and February HQP will commission two more 256 MW units at Eastmain-1-A so that ultimately, capacity will have grown by 994 MW. Three major transmission projects are being commissioned: two ±300 Mvar Static Var Compensators at Chénier substation North of Montréal and a 735 kV series compensation project on lines 7024 and 7025 (Chamouchouane – Jacques Cartier) at Jacques Cartier substation near Québec City, and a 345 Mvar 315 kV capacitor bank at Duvernay substation in Montréal.
- Wind generation has grown considerably in the NPCC region since 2007. Wind generation totals in the winter 2007-08: 1,525 MW; 2008-09: 2,337 MW; 2009-10: 3,862 MW, 2010-11: 3,952 MW and 2011-12: 5,261 MW. This translates to a growth of approximately 345 percent since winter 2007-08.
- There is 5,261 MW of nameplate wind capacity in the NPCC region. After applying wind derate factors in the respective Balancing Authority areas, 1,476

MW counts toward capacity. Since the previous winter there has been an increase of 1,309 MW of nameplate wind capacity.

- Based on the CP-8 Probabilistic Reliability assessment study the use of operating procedures designed to mitigate resource shortages is not expected for Québec, Ontario, and New York under both the assumed Base and Severe Case conditions for the expected load level. Only the Maritimes Area shows a possibility of reducing 30-minute reserves and to call on interruptible loads in response to a capacity deficiency this winter for these conditions.
- Based on the CP-8 Probabilistic Reliability assessment study only the Maritimes Area shows a possibility of reducing 30-minute reserves and to call on interruptible loads in response to a capacity deficiency this winter for the extreme load level if the severe set of resource unavailability assumptions used in this analysis occurs.
- Environmental constraints, specifically state, provincial and local regulations may have some minor impact at various times throughout the 2011-12 Winter Operating Period.
- No particular fuel availability problem is foreseen by any of the Balancing Authority Areas.
- Communication protocols in place are sufficient to ensure the timely and efficient communications in all Balancing Authority Areas to maximize the availability of emergency support.
- The winter assessment indicates that each NPCC Area is reasonably prepared and is reviewing the necessary strategies and procedures to deal with operational problems and emergencies if they develop. The CO-12 Working Group believes that these preparations are valid for dealing with the various operating scenarios expected during the Winter Operating Period.

The results of the CO-12 and CP-8 Working Groups' studies indicate that NPCC and the associated Balancing Authority Areas have adequate generation and transmission for the Winter Operating Period and have developed the necessary strategies and procedures to deal with operational problems and emergencies as they may develop. However, the resource and transmission assessments in this report are mere snapshots in time and base case studies. Continued vigilance is required to monitor changes to any of the assumptions that can alter this report's findings.

2. Introduction

The NPCC Task Force on Coordination of Operation (TFCO) established the CO-12 Working Group to conduct overall assessments of the reliability of the generation and transmission system in the NPCC Region for the Summer Operating Period (defined as the months of May through September) and the Winter Operating Period (defined as the months of December through March). The Working Group may occasionally study other conditions as requested by the TFCO.

For the 2011-12 Winter Operating Period[3] the CO-12 Working Group:

- Examined historical winter operating experiences and assessed their applicability for this period.
- Examined the existing emergency operating procedures available within NPCC and reviewed recent operating procedure additions and revisions. The NPCC CP-8 Working Group has done a probabilistic assessment of the implementation of operating procedures for the 2011-12 Winter Operating Period. The results and conclusions of the CP-8 assessment are included as chapter 9 in this report and the full report is included as Appendix VIII.
- Reported potential sensitivities that may impact resource adequacy on a Reliability Coordinator Area basis. These sensitivities included temperature variations, new wind generation, delays to in-service of new generation, load forecast uncertainties, evolving load response measures, solar magnetic activity, system voltage and generator reactive capability limits.
- Reviewed the communications protocols with participants to ensure that timely and efficient communications will be in place in all Reliability Coordinator Areas to maximize the availability of emergency support.
- Reviewed the capacity margins accounting for bottled capacity within the NPCC.
- Reviewed inter-Area and intra-Area transmission adequacy, including new transmission projects, upgrades or derates and potential transmission problems.
- Reviewed the operational readiness of the NPCC region and actions to mitigate potential problems.
- Assessed the implications of strategies adopted for the Winter Operating Period on the adequacy of supply in the shoulder months.
- Coordinated data and modeling assumptions with NPCC CP-8 Working Group, and documented the methodology of each Reliability Coordinator area in its projection of load forecasts.

[3] For the purposes of this report, the Winter Operating Period includes the week beginning November 27, 2011 to the week beginning March 31, 2012 inclusive.

- Coordinated with other parallel seasonal operational assessments including the Eastern Interconnection Reliability Assessment Group (ERAG) SERC East - Reliability*First* – NPCC and the NERC Reliability Assessment Subcommittee (RAS) Assessments.

3. Demand Forecasts for Winter 2011-12

The non-coincident forecasted peak demand for NPCC over the 2011-12 Winter Operating Period is 111,958 MW. This peak demand translates to a coincident peak demand of 111,821 MW which is expected during the week beginning January 15, 2012. Demand and Capacity forecast summaries for NPCC, Maritimes, New England, New York, Ontario, and Québec are included in Appendix I.

Ambient weather conditions are an important variable impacting the demand forecasts. However, unlike the summer demand forecasts, the non-coincident peak demand varies only slightly from the coincident peak forecast in the winter. This is mainly due to the fact that the drivers that impact the peak demand are concentrated into a specific period in time. In winter, the peak demands are determined mainly by low temperatures along with the reduced hours of daylight that occurs over the first few weeks of January.

While the peak demands appear to be confined to a few weeks in January, each Area is aware that reduced margins could occur during any week of the operating period as a result of weather variables and / or higher than normal outage rates.

The impact of ambient weather conditions on load forecasts can be demonstrated by various means. The IESO and Maritimes represent the resulting load forecast uncertainty in their respective Areas as a mathematical function of the base load. The NYISO use a weather index that relates air temperature and wind speed to the load response and increases the load by a MW factor for each degree below the base value. TransÉnergie — the Québec system operator — updates forecasts on an hourly basis within a 12 day horizon based on information on local weather, wind speed, cloud cover, sunlight incidence and type and intensity of precipitation over nine regions of the Québec Balancing Authority Area. ISO-NE relates air temperature to the load response and increases the load by a MW factor for each degree below the base value.

The method each Reliability Coordinator area uses to determine the peak forecast demand and the associated load forecast uncertainty relating to weather variables is described in Appendix IV. Below is a summary of all Reliability Coordinator Area forecasts.

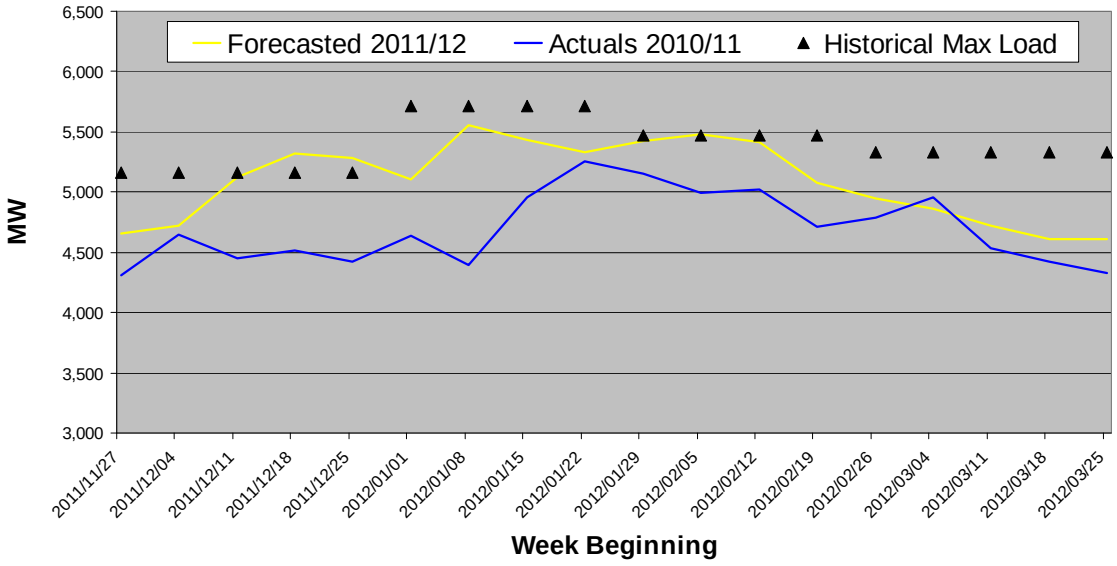
Summary of Reliability Coordinator area Forecasts

Maritimes

Based on the Maritimes Area winter 2011-12 demand forecast, a peak of 5,552 MW is predicted to occur for the Winter Operating Period, December through February. The peak demand is forecasted to occur the week beginning January 8, 2012. The forecasted peak is approximately 6 percent higher than last year's actual winter peak of 5,252 MW which occurred January 24, 2011. This can be explained as last winter was milder than expected. During the NPCC forecasted peak week beginning January 15, 2012 the Maritimes Area has forecasted a load of 5,430 MW.

It should be noted that the Maritimes Area load is simply the mathematical sum of the forecasted weekly peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). As such, it does not take the effect of load coincidence within the week into account. If the total Maritimes load included a coincidence factor, the forecast load would be approximately 1-3 percent lower. The following graph illustrates the weekly Maritimes forecast.

Figure 1
Maritimes Winter 2011-12 Weekly Load Profile

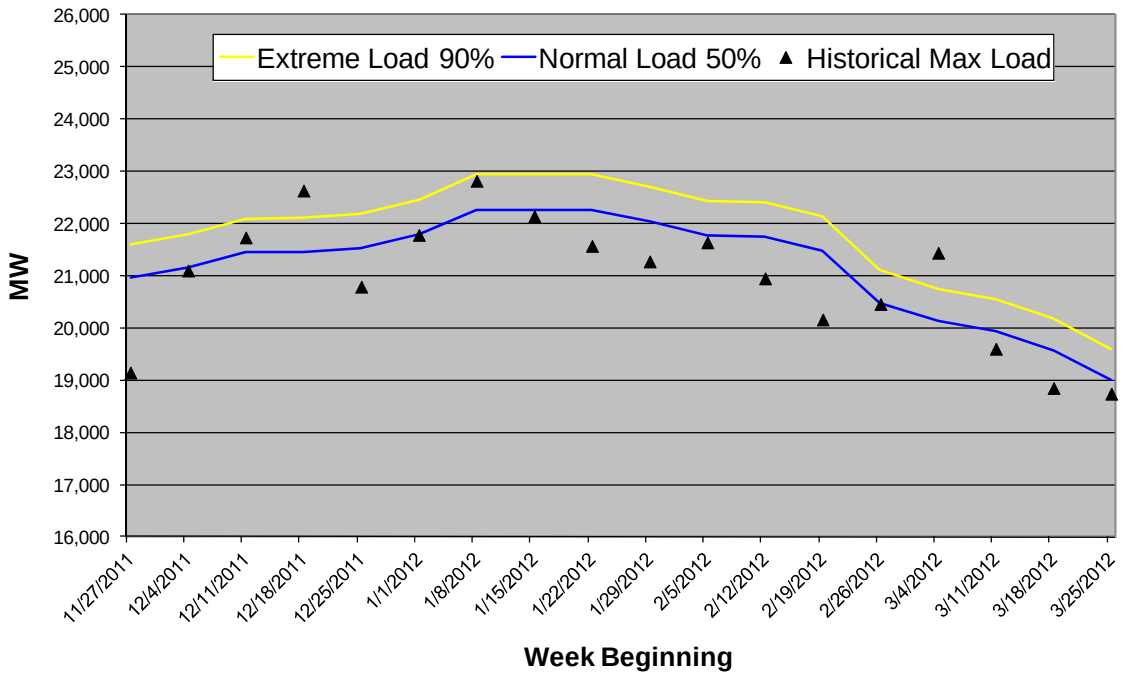


New England

The New England Balancing Authority Area reference forecast (50 percent chance of being exceeded) for winter 2011-12 projects a peak demand of 22,255 MW. This projected peak is 170 MW (0.77 percent) higher than the 2010-11 winter projected peak of 22,085 MW, and 310 MW (1.41 percent) higher than the actual 2010-11 weather normal winter peak of 21,945 MW. The key factors driving this fairly level forecast are the continued penetration of energy efficiency and the lingering effects of the economic recession. New England's all-time winter peak demand of 22,818 MW occurred on January 15, 2004. If extremely cold weather occurs for a prolonged period during the upcoming Winter Operating Period, the winter peak demand could reach 22,935 MW (10 percent chance of being exceeded).

The following graph illustrates the range of potential peak demands that ISO-NE may experience this winter and compares them to historical peaks (1980-2010).

Figure 2
New England Winter 2011-12 Weekly Load Profile

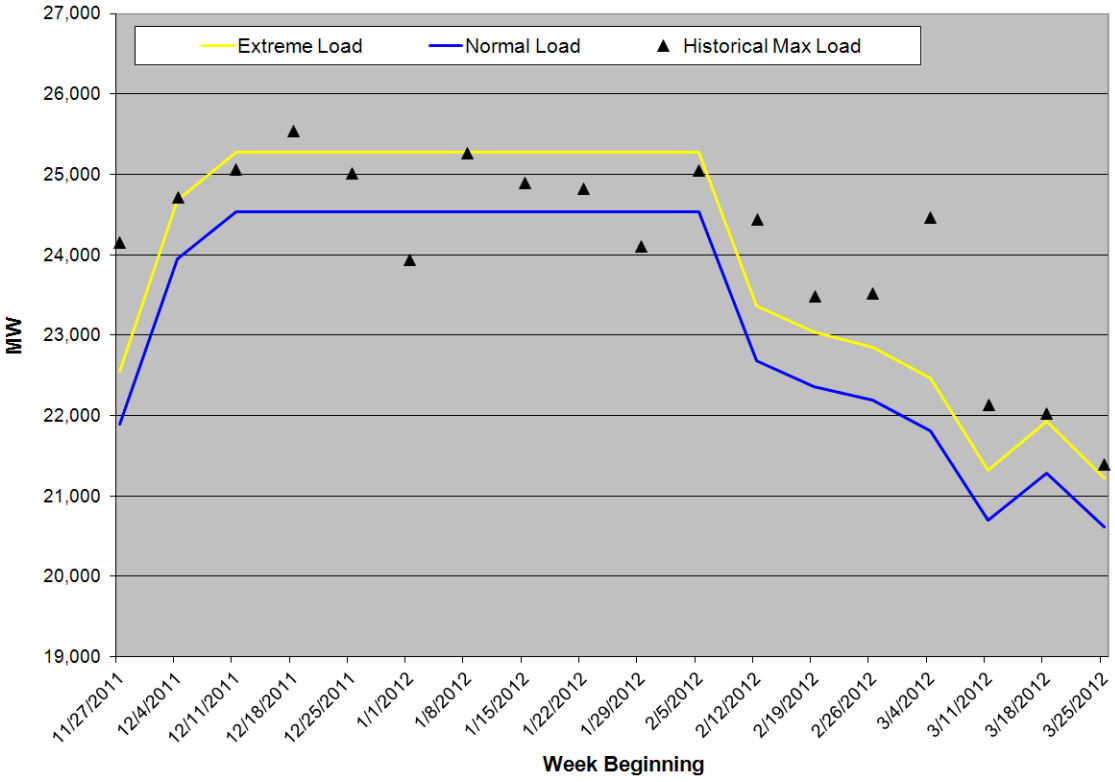


New York

The New York Balancing Authority 2011-12 winter peak load forecast is 24,533 MW, which is 244 MW higher than the forecast of 24,289 MW peak for the 2010-11 winter and 121 MW less than the actual winter peak in 2010-11 of 24,654 MW. This forecast load is 3.95 percent lower than the all-time winter peak load of 25,541 MW that occurred on December 20, 2004. The daily peak demand observed by New York during the Winter Operating Period occurs in the late afternoon or early evening hours.

The following illustration provides the range of potential peak demands that New York may experience this winter.

Figure 3
New York Winter 2011-12 Weekly Load Profile

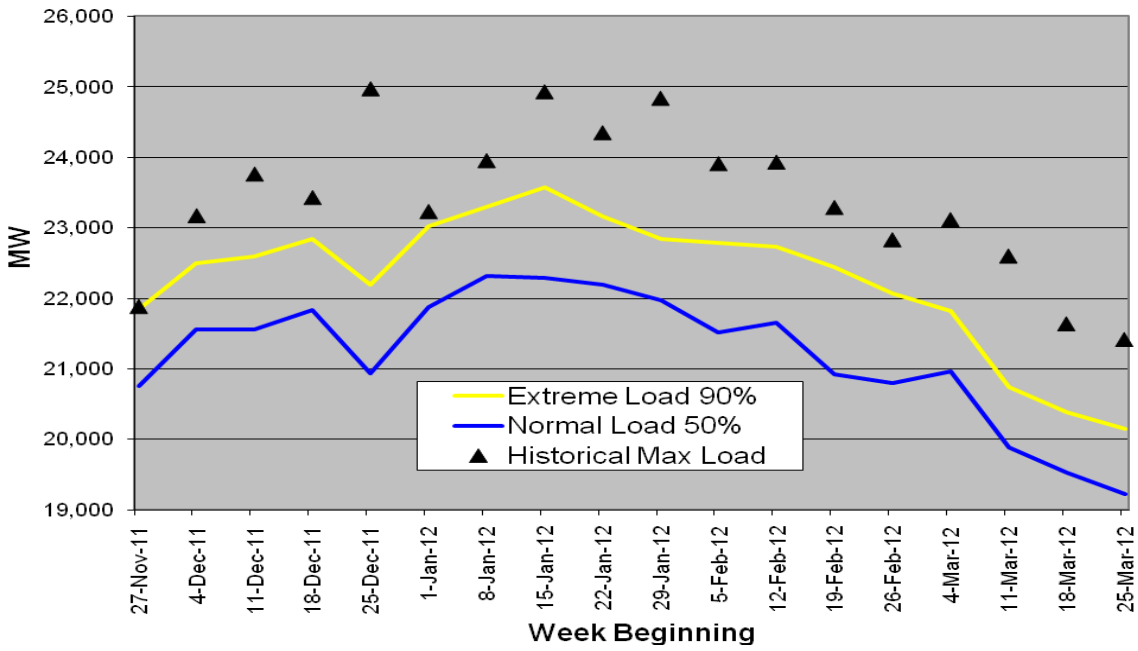


Ontario

The forecasted weather normal hourly peak demand for this Winter Operating Period is 22,311 MW. This is 163 MW lower than the 22,474 MW forecasted last winter and 422 MW lower than last winter's actual peak of 22,733 MW. The actual peak demand for the 2010-11 Winter Operating Period occurred on January 24, 2011. The forecasted peak demands are expected to decline in comparison to last winter because of the continued growth in embedded (distributed) generation and conservation programs.

The following graph illustrates the range of possible demands that the IESO may experience over this Winter Operating Period. The peak demand is forecast for the week beginning January 8, 2012, however, the peak can occur at anytime during the season, from the week beginning December 04, 2011 to the week beginning February 26, 2012.

Figure 4
Ontario Winter 2011-12 Weekly Load Profile



Québec

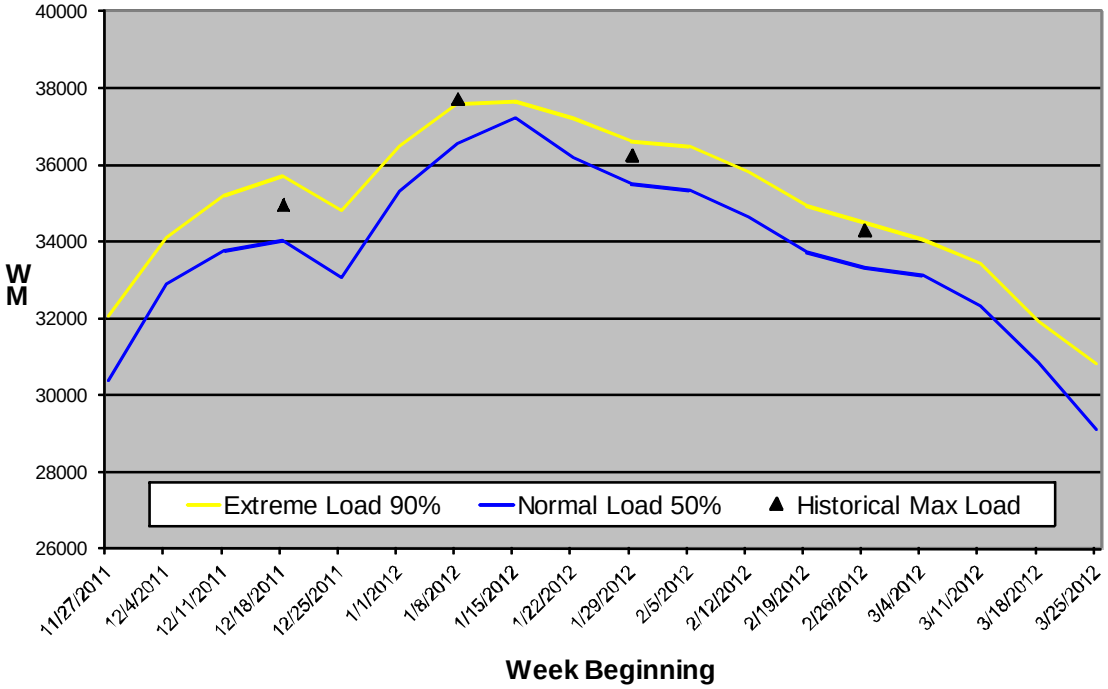
The Québec Balancing Authority Area is winter peaking. Hydro-Québec's reference peak internal demand forecast for the 2011-12 Winter Operating Period is 37,153 MW, predicted to occur during the week beginning January 15, 2012. This is 208 MW higher than the 2010-11 forecast of 36,945 MW. This modest (0.56 percent) growth is due to a residential and commercial sector increase. The actual internal peak demand for the 2010-11 Winter Operating Period was 37,717 MW which occurred on January 24, 2011 at 8h00 EST. This constitutes a new all-time peak internal demand record. (See "Post-Seasonal Assessment and Historical Review" section, below).

These values do not include the supply of 145 MW of load to Cornwall over the Cedar Rapids Transmission (CRT) system (154 MW with losses). This load in the Cornwall area of Ontario is tapped-off CD11 and CD22 120 kV lines which are in a radial configuration (not connected to TransÉnergie's main grid) from Les Cèdres Generating Station in Québec to Dennison in New York. This load is served by Québec. For this reason, the Cornwall load is included in Table 6, Appendix I. The demand forecast in Table 6 for the week beginning January 15 is therefore 37,153 + 154 = 37,307 MW.

Throughout the Winter Operating Period, as seen in Table 6, weekly peak demand varies from 30,454 MW for the week beginning November 27 to 37,307 MW for the week beginning January 15 and back to 29,178 MW for the week beginning March 27.

The following graph demonstrates the range of potential weekly peak demands on the Québec system for the 2011-12 Winter Operating Period.

Figure 5
Québec Winter 2011-12 Weekly Load Profile



4. Resource Adequacy

NPCC Summary for Winter 2011-12

The following assessment of resource adequacy indicates the week with the highest coincident NPCC demand is the week beginning January 15, 2012. Detailed Projected Load and Capacity Forecast Summaries specific to NPCC and each Area are included in Appendix I.

Table 1, Appendix I is the NPCC load and capacity summary for the 2011-12 Winter Operating Period. Appendix I, Tables 2 to 6, contain the load and capacity summary for each NPCC Balancing Authority area. Each entry in Table 1 is simply the aggregate of the corresponding entry for the five NPCC Balancing Authority Areas.

Table 1 (below) summarizes the load and capacity situation for the peak week beginning January 15, 2012 compared to the winter 2010-11 forecasted peak week (week beginning January 9, 2011).

TABLE 1

Comparison of Resource Adequacy for NPCC

2011-12 Forecast and 2010-11 Forecast

All values in MW	Forecasted week of Jan. 15, 2012 2011-12 Forecast	Forecasted week of Jan. 9, 2011 2010-11 Forecast	Difference
Installed Capacity	156,931	156,084	847
Purchases	0	0	0
Sales	0	0	0
Total Capacity	**156,931**	**156,084**	**847**
Coincident Demand	111,821	110,958	863
Demand Response	6,914	4,475	2,439
Maintenance/De-rate	16,099	12,758	3,341
Required. Reserve	7,548	7,248	300
Unplanned Outages	9,736	9,982	-246
Net Margin	**18,641**	**19,613**	**-972**

Even though the Installed Capacity and the Demand Response have increased by 847 MW and 2,439 MW, respectively, the Net Margin shows a decrease of 972 MW. This can be primarily attributed to the increase in the amount of planned Maintenance/De-rate when compared to last year.

The following are the assessments for each Balancing Authority Area supporting this overall resource adequacy assessment.

Projected Capacity Analysis by Reliability Coordinator area

Maritimes

The Installed Capacity for the assessment period is between 7,676 MW and 7,686 MW. The 10 MW increase is a wind farm scheduled to be in-service the week of January 1, 2012. The Total Capacity available during the forecasted peak load week for the Maritimes Area is 7,852 MW when firm sales and purchases are taken into account and occurs the week of January 8, 2012. The same amount of Total Capacity is also available during the NPCC projected peak week of January 15, 2012.

The Point Lepreau Nuclear station (approximately 658 MW) is out for refurbishment and is not expected back this Winter Operating Period. It was originally scheduled to be completed October 2009 but has since been delayed. The latest in-service date released is September 2012.

When allowances for known maintenance and de-ratings, required operating reserve and unplanned outages are considered, the Maritimes Area is projecting adequate net margins for the Winter Operating Period. These net margins range from 455 MW to 1,375 MW (8 percent to 30 percent). The corresponding 2010-11 winter Maritimes net margin range was 8 percent to 26 percent.

The Maritimes Area assesses its seasonal resource adequacy in accordance with NPCC Directory 1, Appendix F Procedure for Operational Planning Coordination. As such, the assessment considers the regional operating reserve criteria; 100 percent of the largest single contingency and 50 percent of the second largest contingency.

The Maritimes area is forecasting normal hydro conditions for the 2011-12 Winter Operating Period. The Area's hydro resources are run of the river facilities with limited reservoir storage facilities. These facilities are primarily utilized as peaking units and providing operating reserve.

The Maritimes Area is not relying on outside assistance/external resources during the Winter Operating Period.

New England

With the expected weather and normal resource outages, capacity within New England is forecasted to be sufficient to meet load plus operating reserve requirements during this Winter Operating Period. The lowest projected net margin of 2,960 MW (13 percent) is expected to occur during the week beginning January 15, 2012 while the highest projected net margin of 7,543 MW is expected to occur during the week

beginning March 25, 2012, if all assumed system conditions materialize under the reference load forecast (50 percent chance of being exceeded).

The net margin is based on known outages, an allowance for unplanned outages[4], anticipated generation additions and retirements, projected firm purchases and sales, and the impact of expected Demand Response Programs.

In addition to the allowance for unplanned outages, an allowance for higher unplanned outages due to possible natural gas shortages of New England generators is included in the seven highest load weeks of January and February. This allowance, which is assumed to be 2,000 MW under the reference load forecast, significantly decreases the forecasted net margins during the weeks of January 8 through February 19.

During times of capacity deficiencies, ISO New England invokes ISO-NE Operating Procedure No. 4 – *Actions during a Capacity Deficiency* (OP-4), which includes public appeals for conservation, purchasing emergency energy from the neighboring Areas, interrupting real time demand response providers, and implementing voltage reductions.

While ISO New England expects to have adequate margins for this winter under expected weather and normal resource outages, if operable capacity shortages occur due to higher than expected resource unavailability or higher than expected load conditions, ISO New England may have to implement ISO-NE OP 4 or ISO-NE Operating Procedure No. 21 – *Action during an Energy Emergency* (OP 21). OP 21 is an emergency operating procedure designed to provide additional commitment and dispatch flexibility to manage and conserve fuel-limited supply-side resources.

New York

The NYISO forecasts available installed capacity of 34,329 MW for the peak week demand forecast of 24,533 MW. Available installed capacity is the total installed capacity less known planned and predicted forced outages. Accounting for purchases, sales, required operating reserve, demand response, planned and unplanned outages results in a Net Margin of 11,035 MW.

These resources represent all generation capability located physically within the New York Balancing Authority Area that is able to participate in the NYISO ICAP market. In addition to these generation resources within the New York Balancing Authority Area, generation resources external to the New York Balancing Authority Area can also participate in the NYISO ICAP market. Resources within the New York Balancing Authority Area that provide firm capacity to an entity external to the New York Balancing Authority Area are not qualified to participate in the ICAP market.

[4] The allowance for unplanned outages is based on historical trends and is estimated to be between 2,200 MW and 3,200 MW during the winter.

NYISO conducts semi-annual and monthly Installed Capacity (ICAP) auctions. Based on the forecast load for 2011, the ICAP requirement is 28,336 MW based on a 15.5 percent installed reserve margin (IRM) requirement. Last year the IRM requirement was 18 percent. In addition to the generation resources within the New York Balancing Authority Area, generation resources external to the New York Area can also participate in the NYISO ICAP market. An external ICAP supplier must declare that the amount of generation that is accepted as ICAP in NY will not be sold elsewhere. The external Area in which the supplier is located has to agree that the supplier will not be recalled or curtailed to support its own loads; or will treat the supplier using the same pro rata curtailment priority for resources within its Balancing Authority Area. The energy that has been accepted as ICAP in NY must be demonstrated to be deliverable to the NY border. The NYISO sets a limit on the amount of ICAP that can be provided by suppliers external to NY. When allowances are taken for scheduled and unplanned outages (based on historical performance of 5.67 percent unavailable capacity), the net available resources will be 34,329 MW. This will be sufficient to meet the New York Balancing Authority Area load and operating reserve requirement during the peak load hours, with an additional reserve margin of approximately 8,962 MW expected at peak conditions.

Generation retirements since the winter 2010-11 period total 246 MW. The Greenidge Unit 4 (108 MW, March 2011), Westover Unit 8 (80 MW, March 2011), and Barrett #7 (18 MW, October 2011) units have all retired. Ravenswood GT 3-4 (40 MW) is scheduled to retire in November 2011.

NYISO expects approximately 549 MW of load relief from emergency operating procedures that include internal load curtailment by the transmission owners, public appeals and 5 percent system wide voltage reductions during forecast peak demand conditions. Participation in the Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) programs represents an additional 1,882 MW and 166 MW, respectively, available through the market. EDRP participants voluntarily curtail load when requested by the NYISO. SCR participants must, as part of their agreement, curtail power usage, usually by shutting down when asked by the NYISO.

Ontario

The IESO begins the Winter Operating Period with an installed generating capacity of 34,975 MW after adding 75 MW from wind and 15 MW of Biomass from our current capacity of 34,882 MW. By the end of the assessment period, the installed capacity will decrease by 62 MW to 34,913 MW. This decrease includes the retirement of two units at Nanticoke generating station which represents a reduction of 980 MW in the coal fired capacity by the end of the year. The change in capacity also includes the addition of two wind projects with a total capacity of 168 MW which are scheduled to be in service for January and February 2012 and the return of a refurbished nuclear unit (750 MW) by first quarter of 2012.

The IESO expects to have adequate margins for this winter under expected weather and normal resource outages. These net margins range from 3,505 MW to 6,446 MW. The

lowest projected net margin of 16.9 percent is expected to occur during the week beginning November 27, 2011 while the highest projected net margin of 30.8 percent is expected to occur during the week beginning December 25, 2011 if all planned outages are allowed to proceed as requested.

This analysis is based on a review of known outages, a projection of unplanned outages, and a forecast of price responsive loads. Known outages include those resources that are scheduled to be on planned outages, transmission constrained resources as well as the difference between the installed capacity and the dependable capacity associated with certain resources. Unplanned outages represent an estimate of the forced outages that may be experienced in this study period.

The IESO forecasts the future price responsive load based on Market Participant registered data and consideration of actual market experience. The net margin shown in Table 5 of Appendix I, does not consider that the IESO has several demand management programs which are implemented as part the IESO's Emergency Operating State Control Actions. For example, the IESO can institute a 3 percent or a 5 percent voltage reduction which has the effect of reducing the demand by 1.5 percent and 2.6 percent for a short period of time.

The risks associated with this analysis are that demands may be heavier than expected due to extreme weather, generators on outage may not return to service as scheduled or generators forced from service may be higher than projected. The projected margins and control actions available to the IESO are continuously assessed. Should the IESO determine that the Ontario Area is deficient; the appropriate course of action will be taken. Actions can include the adjustment of outage programs, securing assistance via market mechanisms or the acquisition of emergency energy from other Areas as a final step.

Québec

Installed Capacity

For the 2011-12 Winter Operating Period the installed capacity in the Québec Balancing Authority Area will total 43,394 MW in February 2012. Installed capacity for the 2010-11 period was 42,400 MW. The Eastmain-1-A hydro generating station is presently being placed in service. One 256 MW unit is now in service, a second unit will be in service January 1, and the third unit will be in service February 1. Four new wind projects will be on-line for the winter period (see Wind Power section below). During last winter's operating period Tracy Unit A-4 was out of service. This unit has now been definitely retired. Minor capacity adjustments due to generator characteristic changes, water level and temperature adjustments have been made, as usual.

For February 2012, the capacity increase breakdown is the following:

Eastmain-1-A	+768 MW
New wind generation	+400 MW

Tracy A-4 retirement	-150 MW
Various generation adjustments	-24 MW
Total	**+994 MW**

Purchases, Sales and Interruptible Load

Each year, the Load Serving Entity in Québec (HQD) proceeds with short-term capacity purchases (UCAP) in order to meet its capacity requirements if needed. These purchases may be supplied by resources located in Québec or in neighboring markets. For this purpose, HQD has designated the Massena - Châteauguay (1,000 MW) and the Dennison - Langlois (100 MW) interconnections to meet its resource requirements during winter peak periods.

Hydro-Québec Production (HQP) may also from time to time, resort to purchases from external markets to fill in its obligations.

The Area will import 775 MW in January and 650 MW in February from external markets.

Firm sales of 310 MW to ISO-NE and of 300 MW to New Brunswick are expected for January and February. However, sales to New Brunswick will be 100 MW only during December and March.

Table 6, Appendix I presents 1,565 MW of interruptible load and Direct Control Load management for the Québec Area. This is discussed further in the Demand Response Programs section, below.

Known Maintenance/Constraints

In the Québec Area, in winter, the Known Maintenance/Constraints column of the Load and Capacity table mainly reflects hydraulic restrictions on Hydro-Québec Production's (HQP) various generating stations with a few other particular constraints on other generating stations. In early December, numbers show the effect of some late generator maintenance still ongoing at this time. Numbers in January, February and March reflect hydraulic restrictions and outages.

In this assessment, the 547 MW natural gas unit operated by TransCanada Energy at Bécancour has been mothballed. On June 10, 2011, HQD filed a request with the Québec Energy Board to renew the temporary shutdown for 2012. This shutdown for year 2012 was approved by the Régie on August 2, 2011. Moreover, HQP has decided to mothball the last three units (450 MW) at Tracy fossil fuel G.S.

Two hydro units presently on outage will not be returned to service at the beginning of the Winter Operating Period. Unit A-2 at Churchill Falls (486 MW) is expected to return

to service on January 21, 2012. Unit A-23 at Bersimis-2 (142 MW) is not expected back until June 2012.[5] Churchill Falls and Labrador Corporation's contract with Hydro-Québec Production calls for a 4,765 MW delivery to Québec. Churchill Falls' capability is greater than this. When Labrador load is accounted for and considering the generating station's capability, the actual impact of this outage on electricity deliveries will be 350 MW.

This brings inoperable resources for the forecasted peak week (week beginning January 12) to 1,489 MW. They are included in the Known Maintenance/Constraints column from Table 6, Appendix I. Finally, it should be mentioned that historically during January, a 560 MW hydraulic restriction is imposed at Beauharnois G.S., near Montréal for ice-cover formation. This explains why restrictions are higher in January than in February.

Numbers vary from 4,489 MW in early December to 2,923 MW in late January and 3,434 MW in March. Restrictions and outages are generally higher than what was posted for the last Winter Operating Period.

Required Operating Reserve

Historically, the required operating reserve for the Québec Balancing Authority Area has been set at 1,500 MW. This is based on the largest single contingency on the system, the loss of a Churchill Falls 230/735 kV transformer, typically carrying 1,000 MW. For this Winter Operating Period, this is again the basis for the reserve calculation.

The required operating reserve shown in Table 6, Appendix I for the 2011-12 Winter Operating Period is therefore set at 1,500 MW.

Net Margin

As mentioned in the Summary of Area Forecasts section above, the winter peak is expected to materialize during the week of January 15, 2012. Forecast internal peak demand is 37,153 MW. 154 MW is added to this amount for the Cornwall load. Total peak load in Table 6 of Appendix I is therefore set at 37,307 MW. Firm sales to neighboring systems, excluding Cornwall, amount to 650 MW. Capacity purchases from neighboring areas amount to 775 MW. When required operating reserve, interruptible load and allowances for unplanned outages and load uncertainty are taken into account, the Net Margin at peak load is 688 MW (1.8 percent). In order to maintain appropriate reserve margins the Québec Area has access to additional capacity or energy purchases from New York and Ontario markets through existing interconnections.

[5] These outages are not accounted for in the NERC 2011-12 Winter Assessment and other reliability assessments. Information on these outages has only become known recently during the development of this assessment. This assessment's development time frame allows such outages to be reported to the end of October.

The Net Margin varies from 2,604 MW during mid-December to 688 MW at peak load to 8,911 MW during late March as can be observed in Table 6, Appendix I.

Recent and Anticipated Generation Resource Additions

The following Table lists the recent and anticipated generation resource additions and retirements.

TABLE 2

Recent and Anticipated Generation Resource Additions and Retirements

2010-11 Winter through 2011-12 Winter

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	In Service Date
Maritimes	Lameque (New Brunswick)	45	Wind	March 2011
	(Located in Prince Edward Island)	10	Wind	Jan 2012
New England	Berkshire Wind Power Project	15	Wind	May 2011
	Middletown 12 - 15	196.8	Oil/Nat. Gas	June 2011
	Kleen Energy	620	Nat. Gas/Oil	July 2011
	Rollins Wind Plant	60	Wind	July 2011
	Sheffield Wind	40	Wind	Oct 2011
	Record Hill Wind	50	Wind	Dec 2011
	Granite Reliable Power	99	Wind	Dec 2011
New York	Greenidge Unit 4 (Retirement)	-108	Coal	March 2011
	Westover Unit 8 (Retirement)	-80	Coal	March 2011
	Astoria Energy II	617.2	Natural Gas	June 2011
	Upton Solar Farms	32.0	Solar	Oct 2011
	Barrett #7 (Retirment)	-18	Natural Gas	Oct 2011
	Ravenswood GT 3-4 (Retirement)	-40	Natural Gas	Oct 2011
	Howard Wind	57.4	Wind	Oct 2011

Ontario	Sandy Falls (60 Hz)	5	Water	2010-Q4
	Wawaitin (60 Hz)	15	Water	2010-Q4
	Lowe Sturgeon (60 Hz)	14	Water	2010-Q4
	Hound Chute	10	Water	2010-Q4
	Talbot Windfarm	99	Wind	Dec 16, 2010
	Kruger Energy Chatham Wind Project	101	Wind	Dec 22,2010
	Gosfield Wind Project	50	Wind	Jan 7, 2011
	Raleigh Wind Energy Centre	78	Wind	Jan 29, 2011
	Nanticoke units G1 and G2 (shutdown)	-980	Coal	2011-Q4
	Greenwich Wind Farm (RES III)	99	Wind	2011-Q4
	Conestogo Wind Energy Centre 1	69	Wind	2011-Q4
	Bruce Unit 2	750	Uranium	2012-Q1
	Summerhaven Wind Energy Centre	125	Wind	2012-Q1
Québec	Eastmain-1-A Unit A-11	256	Hydro	June 2011
	Eastmain-1-A Unit A-12	256	Hydro	Jan 2012
	Eastmain-1-A Unit A-13	256	Hydro	Feb 2012
	Tracy Unit A-4 (retirement)	-150	Oil	June 2010
	Mont-Louis	101	Wind	July 2011
	Montagne-Sèche	59	Wind	July 2011
	Gros-Morne Phase 1	101	Wind	August 2011
	Le Plateau	139	Wind	Nov 2011

Maritimes

There is a 10 MW wind farm scheduled to be in service the week of January 1, 2012 and no delays are expected. A delay in putting this capacity in service will not impact reliability in the Maritimes.

New England

Two wind projects, Granite Reliable Power and Record Hill Wind, are expected to go commercial in New England during the Winter Operating Period. A delay in the commercial operation of these projects will not have an adverse impact on New England's reliability.

New York

New generating projects with nameplates totaling 649.2 MW have come into service since the 2010-11 Winter Operating Period. A new wind project, Howard Wind, with a nameplate of 57.4 MW is projected to be in service in December, 2011.

Ontario

There will be 750 MW of nuclear generation and 293 MW of wind generation to be added for the 2011-12 Winter Operating Period. This will be offset by the retirement of 980 MW of coal. Any delay in any of these projects will not impact reliability in Ontario.

Québec

No delays are expected for the Eastmain-1-A commissioning. Wind plants are presently in service.

Fuel Infrastructure by Reliability Coordinator area

The following is a self-assessment by each Reliability Coordinator area of the expected fuel supply infrastructure.

Maritimes

The Maritimes Area does not consider potential fuel-supply interruptions in the regional assessment. The fuel supply in the Maritimes Area is very diverse and includes natural gas, diesel, coal, oil (both light and residual), hydro, tidal, municipal waste, wind and wood. Fuel supplies are expected to be adequate during the projected winter period. Extreme weather conditions should have no impact on the fuel supply to the Maritimes Area. Responsibility for fuel switching plans lies with the generation owner. All applicable units have the required procedures. The only generator units with fuel-switching capability are at Tuft's Cove, Nova Scotia (natural gas or oil) and Coleson Cove unit #3, New Brunswick (oil or oil/petcoke) and totaling 645 MW. Each facility maintains an adequate supply of its primary fuel.

New England

The majority of power generators within New England are fueled by natural gas, followed by oil, nuclear, coal, hydro and renewable resources. In 2010, gas-fired generation produced over 45 percent of the region's electric energy production. New England's heavy reliance on natural gas to produce electricity has produced some winter reliability concerns in the past, primarily due to the direct competition with the core natural gas markets for both gas supply and regional transportation during extreme winter weather conditions. In addition to discussing the winter outlook with regional stakeholders, ISO-NE has attended several regional fuel supply conferences and seminars, and reports that no fuel supply or deliverability concerns have been identified for this winter.

During extremely cold winter days, there may be fuel supply restrictions on natural gas-fired generating units, due to regional gas pipelines invoking delivery prioritization amongst their entitlement holders. Such conditions routinely occur, resulting in temporary reductions in gas-fired capacity. These temporary reductions to operable capacity are reflected within ISO-NE's forced outage assumptions. ISO-NE monitors these potential situations and mitigates their effects by dispatching non-gas-fired resources to replenish these temporary forced outages.

ISO-NE routinely gauges the impacts that fuel supply disruptions could have upon system or subregional reliability. ISO-NE continuously monitors the regional natural gas pipeline systems, via their Electronic Bulletin Board (EBB) postings, to ensure that emerging gas supply or delivery issues can be incorporated into and mitigated within the daily or next-day operating plans. Should natural gas issues arise, ISO-NE has predefined communication protocols in place with the Gas Control Centers of both regional pipelines and local gas distribution companies (LDCs), in order to quickly understand the emerging situation and subsequently implement mitigation measures. ISO-NE has two procedures that can also be invoked to mitigate regional fuel supply emergencies impacting the power generation sector:

1) ISO-NE's Operating Procedure No. 21 - *Action During an Energy Emergency* (OP 21) is designed to help mitigate the impacts on bulk power system reliability resulting from the loss of operable capacity due to regional fuel supply deficiencies that can occur anytime during the year. Fuel supply deficiencies are the temporary or prolonged disruption to regional fuel supply chains for coal, natural gas, LNG, and heavy and light fuel oil.

2) ISO-NE's Market Rule No. 1 – Appendix H – *Operations during Cold Weather Conditions* is a procedure that is designed to help mitigate the impacts on bulk power system reliability resulting from the loss of operable capacity due to the combined effects from extreme cold winter weather or constraints with regional natural gas supplies or deliveries.

The ongoing reliability concern for this winter involves the reliability implications to the electric power system resulting from very extreme winter weather or a *"force majeure"* type event on the regional natural gas system. As noted by the events that occurred in the southwest during February 2011, extreme winter weather has the capability to impact the availability of generation by inducing cold weather-related outages. Although the majority of New England's generation fleet took various remedial actions to "cold weather-proof" their stations after the Cold Snap of January 2004, portions of the fleet may still be susceptible to outages induced by extreme winter weather. In addition, an extreme contingency located upstream or on the regional natural gas grid, although temporary in nature, could create regional gas supply shortages, which would primarily affect the regional gas-fired generation fleet. Either type of event could quickly diminish the capacity margins projected for the winter, which would require ISO-NE to

implement Emergency Operating Procedures (EOPs) to mitigate the impacts from these events.

New York

Traditionally, New York generation mix has been dependent on fossil fuels for the largest portion of the installed capacity. Recent capacity additions or enhancements now available use natural gas as the primary fuel. While some existing generators in southeastern New York have "dual-fuel" capability, use of residual or distillate oil as an alternate may be limited by environmental regulations. Adequate supplies of all fuel types are expected to be available for the winter period.

Ontario

The majority of generation facilities operating on the IESO-controlled grid are represented by three basic types of fuel - Fossil, Nuclear and Hydroelectric. At the time of this assessment, Oil/Gas generation exceeded coal-fired fossil generation by more than double. This trend is expected to continue as the retirement of four coal-fired units on October 1, 2010 began the move towards eliminating coal-fired generation in Ontario by 2014. The portion of oil fired fossil generation remains relatively unchanged. Generation from biomass technologies is a very small percentage of Ontario's generation mix. Lennox generating station, with a capacity of 2,000 MW, is the only significant dual-fuel facility which can be fueled by oil or gas.

During the winter months, shipping capability is limited by ice and weather conditions on the Great Lakes. This is important because fuel for a portion of the coal-fired resources is delivered by boat via the Great Lakes. While these conditions may prevent delivery for extended periods of time, all sites relying on this delivery mechanism stockpile the fuel.

As in other Areas, natural gas supplies for electricity generation in Ontario also compete with space heating requirements. Natural gas supplies and delivery infrastructures are expected to be adequate for the Winter Operating Period. The IESO and the gas distribution companies in Ontario have an established protocol whereby the gas distribution companies inform the IESO of situations that could affect gas supplies into Ontario.

At the time of this report, the IESO has not been made aware of any fuel supply concerns. It is therefore expected that adequate supplies of all fuels will be available for the Winter Operating Period.

Québec

About 92 percent of the Québec Balancing Authority Area's generating capacity is made up of hydro stations located on geographically dispersed river systems.

Hydro generating plants are classified into three categories: run-of-river plants, annual reservoir and multi-annual reservoir plants. Low water inflows are coped with in different ways for each category:

- Run-of-river hydro plants: relatively constant hydraulic restrictions from year to year.
- Annual reservoir hydro plants: during a year with normal water inflows, these reservoirs are almost full at the beginning of winter. If annual water inflow is low, hydraulic restrictions increase.
- Multi-annual reservoir hydro plants: the target level for multi-annual reservoirs is approximately 50 percent to 60 percent full in order to compensate or store inflows during periods of below or above normal water inflows. Hydraulic restrictions increase during a period of low inflows.

After a severe drought having a 2 percent probability of occurrence, hydro generation on the system would suffer additional hydraulic restrictions of about 500 MW above the "normal conditions" restrictions. Stream flows, storage levels and snow cover are constantly being monitored allowing Hydro-Québec to plan margins to cope with drought periods.

To assess its energy reliability, Hydro-Québec has developed an energy criterion stating that sufficient resources should be available to run through sequences of two or four years of low inflows having a 2 percent probability of occurrence. Hydro-Québec must demonstrate its ability to meet this criterion three times a year to the Québec Energy Board. The last assessment can be found on the Québec Energy Board web site[6].

To smooth out the effects of low inflow cycles, different means have been identified:

- Reduction of the energy stock in reservoirs to a minimum of 10 TWh beginning in May.
- External non-firm energy sales reductions.
- Use of thermal generating units during an extended time period.
- Off-peak purchases from neighboring areas.

[6] http://www.regie-energie.qc.ca/audiences/Suivis/Suivi-D-2008-133_Criteres/HQD_R-3648-2007-AnnexeB_SuiviD2008-133_7dec09.pdf

Wind Capacity Analysis by Reliability Coordinator area

As seen in the wind generation analyses below, there is relatively little wind generation on the system. For the 2011-12 Winter Operating Period, installed wind capacity accounts for approximately 3.3 percent of the total NPCC installed capacity. After applying the derate factor, the amount of wind generation counted towards capacity is only approximately 0.94 percent. Reliability Coordinator areas have different ways of accounting for this generation. The Reliability Coordinator areas are still developing their knowledge regarding operation of wind generation in terms of capacity forecasting and utilization factor.

The following table illustrates the nameplate wind capacity in NPCC for the Winter Operating Period and indicates the capacity derate method used. Some Reliability Coordinator areas include the entire nameplate capacity in the Installed Capacity section of the Load and Capacity Tables and use a derate value in the Known Maintenance/Constraints section to account for the fact that some of the capacity will not be online at the time of peak. Others simply reduce the nameplate capacity by a factor and include this reduced capacity directly in the Installed Capacity section of the Load and Capacity Tables.

Table 3
NPCC Wind Capacity and Derate Methodology

Area	Nameplate Capacity 2011-12(MW)	Capacity After Applied Derate Factor (MW)	Derate Methodology Used
Maritimes	775	158	Derate factors done by sub-areas: Nova Scotia 100 percent. Based on median historical hourly production values from the previous three years for each individual wind facility the following areas use; New Brunswick averages winter 76 percent, summer 75 percent , PEI averages 55 percent winter, summer 70 percent and Northern Maine winter and summer 70 percent
New England	389	118	Based on the average of the median net output during the summer or winter reliability hours during each of the previous years, up to the past five years.
New York	1,311	393	Uses a 70 percent derate factor for the Winter season.
Ontario	1,727	553	Uses seasonal contribution factors based on median historical hourly production values from September 2006 to the present. 89 percent derate for June-August, 76 percent derate for March-May and Sept.-November, 68 percent derate for Dec.- Feb.
Québec	1,059	254	Weather data covering the period between 1971 and 2006 were used to re-simulate coincident hourly load and wind generation in order to estimate the HQD derate factor (70%). The HQP derate factor is 100%.
Total	**5,261**	**1,476**	

Maritimes

The Maritimes Area currently has approximately 775 MW of nameplate installed wind capacity. After applying derates, the current wind capacity is 158 MW.

Wind projected capacity is derated to its demonstrated average output for each summer or winter capability period. In New Brunswick, Prince Edward Island and NMISA each individually wind facility that has been in production for an extended period of

time (three years or more) a derated monthly average is calculated using metering data from previous years over each seasonal assessment period. Nova Scotia does not include any wind facilities towards their installed capacity (100 percent derated).

The Maritimes Area capacity is the mathematical sum of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). Each sub-area's wind generator totals are shown below with their nameplate and derate values.

Table 4

Maritimes Sub-Areas	Nameplate Capacity (MW)
New Brunswick (Winter Derate)	294
Prince Edward Island (Winter Derate)	163.88
Nova Scotia (On-Peak Capacity Factor)	275.4
NMISA (Average yearly Derate)	42
Total	**775.28**

New England

The total nameplate capability of wind generators in New England is 389 MW, of which 184.7 MW is in the Forward Capacity Market (FCM). Approximately 30 percent of that FCM nameplate wind capacity, or 55 MW, has a capacity supply obligation for the 2011-12 commitment period, and is therefore counted toward installed capacity in New England's load and capacity calculations (Table 3, Appendix I).

Table 5

Name	Nameplate Capacity (MW)
Beaver Ridge Wind	4.5
Berkshire Wind Power Project*	15.0
Fox Island Wind	4.5
Kibby Wind Power	132.0
Lempster Wind	24.0
Princeton Wind Farm Project	3.0
Rollins Wind Plant	60.0

Searsburg Wind	6.6
Sheffield Wind	40.0
Stetson Wind Farm	57.0
Stetson II Wind Farm	25.5
Total Wind Projects <2 MW	16.9
Total	**389.0**

The remaining 204 MW of nameplate wind capability is not participating in the 2011-12 Forward Capacity Market, and is therefore considered energy-only. That energy-only wind generation has a derated capacity of 63 MW.

In addition, two new wind projects are expected to go commercial by the end of the year: Granite Reliable Power and Record Hill Wind, with a combined capacity of 149 MW.

New York

New York currently has 1,311 MW of wind capacity. New York applies a 70 percent derate factor for wind generation in the winter operating period resulting in 393 MW counted towards capacity. A new 57.4 MW nameplate wind project, Howard Wind, is expected to come into service during the winter period. It will be interconnected at a new substation, Spencer Hill, on the NYSEG 115 kV system between Bennett and Bath.

Table 6

Name	Nameplate Capacity (MW)
Altona Wind Power	97.5
Bliss Wind Power	100.5
Canandaigua Wind Power	125.0
Chateaugay Wind Power	106.5
Clinton Wind Power	100.5
Ellenburg Wind Power	81.0
Fairfield Wind	74.0
High Sheldon Wind Farm	112.5
Madison Wind Power	11.5
Maple Ridge Wind 1	231.0
Maple Ridge Wind 2	90.7
Munnsville Wind Power	34.5
Steel Winds	20.0
Wethersfield Wind Power	126.0
Total	**1,311.2**

Ontario

Wind generator output varies significantly hour-to-hour or day-to-day. However, over longer periods, wind generation shows more consistent production. The IESO forecasts wind capacity by using seasonal contribution factors based on median historical hourly production values from September 2006 to the present. These factors are updated twice a year and eventually will be calculated using a rolling 10 year data set.

The seasonal wind contribution factors currently in use by the IESO are 32 percent for winter (December, January and February), 11 percent for summer (June, July, August) and 24 percent for shoulder (remaining months).

The IESO presently has 1,727 MW of wind capacity. Below are the currently connected wind generators.

Table 7

Name	Nameplate Capacity 2011 (MW)
Amaranth	200
Comber	166
Dillon	78
Gosfield	50
Greenwich	99
Kingsbridge	40
Point Aux Roches	49
Port Alma	202
Port Burwell	99
Prince Farm	189
Ripley South	76
Spence	99
Underwood	182
Wolfe Island	198
Total	**1,727**

Only 32 percent of nameplate rating is used for wind capacity forecasts for the winter period this equates to 553 MW. The geographic distribution of Ontario wind resources mitigates some of the risk associated with wind capacity variability.

Québec

New wind capacity totaling 400 MW has been commissioned for this Winter Operating Period. These wind plants are Mont-Louis, Montagne-Sèche, Gros-Morne Phase 1, and Le Plateau. Wind capacity now totals 1,059 MW.

The following table shows wind plants in-service for the 2011-12 Winter Operating Period.

Table 8

Name	Nameplate Capacity 2011 (MW)
Le Nordais Cap-Chat (HQP)	57
Le Nordais Matane (HQP)	43
Mont-Copper (HQP)	54
Mont-Miller (HQP)	54
TechnoCentre (HQP)	4
Baie-des-Sables (HQD, first call)	110
Anse-à-Valleau (HQD, first call)	100
Carleton (HQD, first call)	110
St-Ulric/St-Léandre (HQD, first call)	127
Mont-Louis (HQD, first call)	101
Montagne-Sèche (HQD, first call)	59
Gros-Morne Phase 1 (HQD, first call)	101
Le Plateau (HQD, second call)	139
Total	**1,059**

Wind generation under contract with Hydro-Québec Production (212 MW) is derated by 100 percent.

The rest (847 MW) is under contract with HQD and results from its various calls for tenders. For resource adequacy studies, HQD derates its wind capacity by 70 percent.

This is based on detailed wind capacity credit evaluations by HQD which have been presented to the Régie de l'énergie du Québec (Québec Energy Board). The related report is available (in French only) on the Québec Energy Board website[7]. An English article was presented in October 2010 during a workshop dedicated to wind power impacts on power systems[8].

In this report, a wind plant derating of 805 MW is included in the Known maintenance/constraints column in Table 6 of Appendix I, accounting for both HQP and HQD deratings.

In addition to the actual 1,059 MW wind generation capacity, another 2,290 MW are planned to come into service gradually until 2015. Hydro-Québec Distribution's calls for tenders for wind energy are the following:

- first call in 2003 for 990 MW (will finally be 840 MW in 2012)
- second call in 2005 for 2,006 MW (to be commissioned 2011-15)
- third call in 2009 for 500 MW (Only 291 MW has been awarded and should be to be commissioned through 2015)

[7] http://www.regie-energie.qc.ca/audiences/Suivis/Suivi_HQD_PlanAppro.html

[8] L. Bernier, A. Sennoun, "Evaluating the Capacity Credit of Wind generation in Québec", 9th International Workshop on Large Scale Integration of Wind Power into power Systems as well as on Transmission Networks for Offshore Wind power Plants, 18-19 October 2010, Québec City, Canada.

5. Transmission Adequacy

Regional Transmission studies specifically indentifying interface transfer capabilities in NPCC are not normally conducted. However, NPCC uses the results developed in each of the NPCC Reliability Coordinator areas and compiles them for all major interfaces and for significant load areas (Appendix III). Recognizing this, the CO-12 working group reviewed the Normal Transfer Capabilities (NTC) and the Feasible Transfer Capabilities (FTC) between the Balancing Authority Areas of NPCC under peak demand configurations.

The following is a transmission adequacy assessment from the perspective of the ability to support energy transfers for the differing levels, Inter-Region, Inter-Area and Intra-Area.

Inter-Regional Transmission Adequacy

Phase angle regulators (PARs) are installed on all four of the Michigan-Ontario interconnections. One PAR on the Keith-Waterman 230 kV circuit J5D has been in-service and regulating since 1975. The other three available PARs on the Lambton-St. Clair 230 kV circuit L51D and 345 kV circuit L4D and the Scott-Bunce Creek 230 kV circuit B3N remain idle. This is because approval from the Department of Energy on the joint agreement between the IESO, MISO and Hydro One is pending. The DOE may issue the presidential permit at any time.

The operation of the Phase Angle Regulators will assist in the management of system congestion and control of circulating flows.

Inter-Area Transmission Adequacy

The tables in Appendix III provide a summary of the normal transfer capabilities (NTC) on the interfaces between NPCC Balancing Authority Areas and for some specific load zone areas. They also indicate the corresponding feasible transfer capabilities (FTC) under peak conditions based on internal limitations or other factors and indicate the rationale behind reductions from the normal transfer capability.

New York – Ontario intertie BP76, which has been out of service since January 2008, will remain out-of-service until the failed voltage regulator has been replaced at the end of 2012. New York – Ontario intertie PA301 is planned out of service from December 5 - December 16 for clearance to dismantle and remove the failed R76 transformer and start preparing for the new one. At times during this maintenance work, the New York – Ontario interface will be operated to a 0 MW scheduling limit in both directions and the Michigan – Ontario interface will be operated to less than 50 percent of the normal scheduling limits.

Recent and Anticipated Transmission Additions

The following Table lists the recent and anticipated transmission additions.

TABLE 9

Recent and Anticipated Transmission Additions

2010-11 Winter through 2011-12 Winter

Area	Transmission Facility	Voltage (kV)	In Service Date
Maritimes	None		
New England	345/115 kV autotransformer at Kent County Substation, Rhode Island	345/115 kV	June 2011
	345/115 kV autotransformer at the Deerfield Substation in New Hampshire	345/115 kV	Nov 2011
	345/115 kV autotransformer at Wachusett Substation in Massachusetts	345/115 kV	March 2012
	345/115 kV autotransformer at Berry Substation in Rhode Island	345/115 kV	Dec 2011
New York	Sprainbrook-Academy M29	345/138 /13.8	Summer 2011
	Luther Forest	115	Summer 2011
	Stony Ridge	230/115	Summer 2011
	Ramapo-Sugarloaf L28	138	Winter 2011-12
Ontario	Ellwood MTS 230 230/13.2 kV Transformers	230/13.2 kV	Dec 16, 2010
	Glenorchy MTS 230/28 kV Transformers	230/28 kV	June 21, 2011
	Nobel series compensation	500 kV	Dec 4, 2011
	Porcupine 2x200 Mvar shunt capacitor banks	230 kV	2011-Q4
	Hanmer 149 Mvar shunt capacitor bank	230 kV	2011-Q4
	Essa 250 Mvar shunt capacitor bank	230 kV	2011-Q4
	Nanticoke 350 Mvar SVC	500 kV	2011-Q4
	Detweiler 350 Mvar SVC	230 kV	2011-Q4
Québec	Eastmain-1-A to Eastmain-1 Line	315	June 2011

	La Sarcelle to Eastmain-1 Line	315	Spring 2012
	Two Chénier SVCs	735	Dec. 13, 2011
	Series compensation Lines 7024 and 7025	735	Dec. 4, 2011
	345 Mvar Shunt capacitor bank at Duvernay	315	Winter 2011-12

Intra-Area Transmission Adequacy Assessment

Maritimes

The Maritimes bulk transmission system is projected to be adequate to supply the demand requirements for the Winter Operating Period. Part of the TTC calculation with HQ is based on the ability to transfer radial loads onto the HQ system. The radial load number will be calculated monthly and HQ will be notified of the changes. (See Appendix III)

New England

The 2011 Regional System Plan (RSP11) outlines a number of the ongoing transmission planning studies and projects that are taking place. The report continues to describe the various areas of the region where transmission projects are needed for reliability. ISO-NE continually monitors transmission facility additions and coordinates outages in order to mitigate any possible reliability risks that may be associated with changes in the transmission system.

New bulk power transmission facilities that have been placed in service in New England since the 2010-11 winter period include a new 115 kV line between the King Street and West Amesbury Substations in northeastern Massachusetts. This is part of the Merrimack Valley-North Shore Project that addresses various thermal and voltage issues in northeast Massachusetts.

In addition, the expansion of the Kent County 345/115 kV substation was completed in Rhode Island in early 2011. The expansion included installing a second 345/115 kV autotransformer as part of the Greater Rhode Island Transmission Reinforcements Project. These expansions provide additional transformation in the area to address various thermal and voltage issues.

Facilities that are expected to be in service for the upcoming winter include a second 345/115 kV autotransformer at the Deerfield Substation in New Hampshire; a third 345/115 kV autotransformer at the Wachusett Substation, which is part of the Central/Western Massachusetts Upgrade Project in central Massachusetts; and the new Berry substation, with one (1) 345/115 kV autotransformer, which is part of the Greater Rhode Island Transmission Reinforcements project in Rhode Island.

New York

Four significant transmission modifications have occurred since the 2010-11 winter operating period. The Consolidated Edison M29 project consists of a circuit from Sprain Brook 345 kV substation to a new substation, Academy 345 kV, then to two three-winding 345/138/13.8 transformers and two 138 kV PAR controlled transformers into Sherman Creek 138 kV.

The Luther Forest Project is National Grid's transmission reinforcement project for their 115 kV transmission system between Rotterdam Substation and Spier Falls Substation. The Project will be located in Saratoga County, New York in the Saratoga/Glens Falls area.

The NYSEG/RG&E Stony Ridge Project includes a new Stony Ridge 230 kV substation, which is located on the Canandaigua-Hillside 230 kV line, and a step-down 230/115 kV transformer into a new Sullivan Park 115 kV substation.

Orange and Rockland has installed a second 138 kV circuit from Ramapo to Sugarloaf, L28, which will be in service in December 2011.

The Watercure 345/230 kV transformer bank, the Norwalk-Harbor-Northport (NNC-1385) 601 line and the South Mahwah-Waldwick J3410 line have returned to service since the 2010-11 Winter Operating Period. The Beck-Packard BP76 remains out-of-service for the winter 2011-12 operating period. The Niagara-Beck (PA-301) will be out-of-service from December 5-16.

Ontario

The system enhancements planned for this winter include the installation of current limiting reactors at Longwood, Clarke, Caledonia and Keith and the addition of shunt capacitor banks at Porcupine, Hanmer and Essa to further improve the north-south transfer capability.

The Queenston Flow West project continues to be delayed. The completion date for the transmission reinforcement between the Niagara and Hamilton-Burlington areas continues to be delayed, prolonging the constraints to the use of available Ontario generation and imports into the province.

A scheduled outage to the Beck Pump Generating Station (PGS) from October 16 to December 2 will impact 230 kV circuit loadings on the Queenston Flow West Interface and on the Niagara Interface. However, Ontario's transmission system is expected to be adequate with planned transmission system enhancements and scheduled transmission outages.

Québec

It was mentioned in the NPCC summer 2011 assessment that a 315 kV line was being built to integrate Eastmain-1-A Generating Station. This is now is service and another 315 kV line to La Sarcelle G.S. will be commissioned to integrate La Sarcelle G.S.. Eastmain-1-A (768 MW) is being commissioned and La Sarcelle G.S. (150 MW) is expected on-line in spring 2012. Other 315, 230, and 161 kV transmission (taps on existing lines) will be placed in service (or is already in service in some cases) to integrate the new above mentioned wind capacity before the winter peak period.

Three major projects to enhance system reliability are being commissioned for the 2011-12 peak period. First, at Chénier 735/315 kV substation (North of Montréal), TransÉnergie is placing two -300/+300 Mvar Static Var Compensators (SVCs) in service. Second, a 735 kV series compensation project is being finalized at Jacques-Cartier 735/315 kV substation (Near Québec City) on the two Chamouchouane – Jacques Cartier lines (lines 7024 and 7025). Each of these two lines will now have 35 percent series compensation. Moreover, a 345 Mvar, 315 kV shunt capacitor bank will be placed in service in the Montréal area for the peak period. (Duvernay)

This equipment is added for the System Reinforcement Project required by TransÉnergie and for the 2 X 1,200 MW firm point to point transmission service requested by Hydro-Québec Production.

No transmission line outages are expected and no major maintenance is scheduled during the 2011-12 Winter Operating Period.

However, Synchronous Condenser CS23 (-100/+300 Mvar) at Duvernay substation in the Montréal area, which became unavailable in June 2008 due to a major transformer fault will not be back in service for the 2011-12 Winter Operating Period. A new transformer for CS23 which was undergoing commissioning tests actually failed again (On-load tap changer failure). Two other synchronous condensers are available at Duvernay. The Duvernay synchronous condenser outage causes 100 MW to 400 MW restrictions on three 735 kV interfaces on the system. Normal transfer capability on these interfaces is usually well over 10,000 MW so that this is not expected to significantly impact transmission reliability for the Winter Operating Period. Impacts due to this outage during previous Winter Operating Periods have in fact been minimal.

Transmission capability for the peak period is adequate to carry the net internal demand plus the firm capacity sales and operating reserve. Moreover, enough transmission capability remains on the system to carry additional resources that would be called upon if load was greater than the forecast.

TransÉnergie continually performs load flow and stability studies to assess system reliability and transfer capabilities on all its internal interfaces. A peak load study is performed annually integrating new generation, new transmission and the latest demand forecasts as well as any unusual operating conditions such as generation and transmission outages.

Extreme cold weather conditions result in a large load pickup over the normal weather forecast and are included in TransÉnergie's Transmission Design Criteria. When designing the system, both steady state and stability assessments are made with winter scenarios involving demands 4,000 MW higher than the normal weather peak demand forecast. This is equivalent to 111 percent of peak winter demand. Hydro-Québec Distribution (the load serving entity) is responsible for the procurement of resources to feed this exceptional demand.

Voltage support in the southern part of the system (load area) is a concern during Winter Operating Periods especially during episodes of heavy load. TransÉnergie has an

agreement with Hydro-Québec Production (the largest Generator Owner on the system) that maintenance on generating units will be terminated by December 1, and that all possible generation will be available. This, along with yearly testing of reactive capability of the generators, ensures maximum availability of both active and reactive power. The end of maintenance on the high voltage transmission system is also targeted for December 1. Also, TransÉnergie has a target for the availability of both high voltage and low voltage capacitor banks. No more than 400 Mvar of high voltage banks should be unavailable during the Winter Operating Period. The target for the low voltage banks is 90 percent availability. This ensures adequate voltage support in the load area of the system.

6. Operational Readiness for 2011-12

Demand Response Programs

Each Reliability Coordinator area utilizes various methods of demand management. The following is a summary of each area's current demand response programs available for the Winter Operating Period.

Maritimes

Interruptible and dispatchable loads are forecast on a weekly basis as indicated in Appendix I, Table 2 and are available for use when corrective action is required within the Area.

New England

During times of capacity deficiencies, ISO New England declares ISO New England Operating Procedure No. 4 (OP 4) – *Actions during a Capacity Deficiency*. That includes: public appeals for conservation, purchasing emergency energy from the neighboring Balancing Authority Areas, activating demand response resources, and implementing voltage reductions.

In the Load and Capacity Table for New England (Table 3, Appendix I), 1,104 MW out of a total of 1,864 MW of demand response resources are assumed available during OP 4 conditions for the 2011-12 Winter Operating Period. In addition to the active demand response resources, there is a total of 760 MW of energy efficiency with FCM obligations.

In addition to the reliability-based programs, ISO-NE also administers a Real-Time Price Response program and offers the Day-Ahead Demand Response Program. Due to their voluntary nature, the 59 MW enrolled in these programs are not included as capacity within the 2011-12 Winter Operating Period in the New England Load and Capacity Table.

New York

Participation in the Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) programs represents an additional 1,882 MW and 166 MW, respectively, available through the market for reliability. The NYISO Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) program may be deployed without time or call frequency limitations in any Operating Period in which the resources are enrolled. EDRP participants voluntarily curtail load when requested by the NYISO when an **operating reserves deficiency or major emergency exists.** SCR participants are required to respond when deployed by the NYISO for reliability**.**

Ontario

A sizeable number of loads within the province bid their load into the market and are responsive to price and to dispatch instructions. Other loads have been contracted by

the Ontario Power Authority to provide demand response under tight supply conditions. The forecast amount of these demand measures has been steadily increasing and now amounts to approximately 1,200 MW in total of which 773 MW is categorized as interruptible.

Québec

Various demand response programs are implemented in the Québec Area.

There are two interruptible load programs. One program – contracted by Hydro-Québec Production – involves large industrial customers (Steel and aluminum foundries) and the other program – contracted by Hydro-Québec Distribution – involves industrial consumers (Paper mills and chemical industries) dispersed in all parts of the system.

The HQP program involves 917 MW of large industrial loads, but due to operating constraints, only 580 MW is considered available. For winter 2011-12, participanting industrial customers to the HQD program totals about 735 MW. The total interruptible load posted is therefore 1,315 MW. Clients must be notified 3 or 18 hours in advance, depending on the nature of the contracts. Follow-up of the interruptible load programs is done by compiling differences between the customers' real consumption and the customers' anticipated hourly load profile at the time the program is scheduled to be in effect. These programs have been in operation for a number of years and according to the records, customer response is highly reliable.

Hydro-Québec Distribution and TransÉnergie have developed a voltage reduction program at a large number of distribution substations. The program is considered by HQD as a 250 MW resource. It is included in the "Demand Response" column in Table 6, Appendix I. Table 6 therefore presents 1,565 MW of load, which consists of interruptible load (1,315 MW) plus the voltage reduction program (250 MW).

A public appeal program is in place to reduce load during heavy load episodes or if a particular event occurs on the system. This has been enforced in 2004, again on January 15 and 16, 2009 and finally on January 24 and 25, 2011 to reduce demands. Demand reduction has been quite variable through the years. It has been estimated at 200 MW to 300 MW in 2011. This is not included in the Load and Capacity table for Québec.

On an operations horizon, if peak demands are higher than expected a number of measures are available to the System Control personnel. Operating Instruction I-001 lists such measures. These vary from limitations on non guaranteed wheel through and export transactions, operation of hydro generating units at their near-maximum output

(away from optimal efficiency, but still allowing for reserves), use of import contracts with neighbouring systems, starting up of thermal peaking units, use of interruptible load programs, and eventually reducing 30-minute reserve and stability reserve, applying voltage reduction, making public appeals, and ultimately using cyclic load shedding to re-establish reserves.

7. Post-Seasonal Assessment and Historical Review

Winter 2010-11 Post-Seasonal Assessment

NPCC

The sections below describe briefly each Balancing Authority Area's 2010-11 winter operational experience. Total NPCC non-coincident demand was 111,416 MW for the period.

Maritimes

The forecasted peak for winter 2010-11 was 5,616 MW.

The actual peak demand of 5,252 MW occurred January 24, 2011.

Control actions were not required.

New England

The forecasted peak for winter 2010-11 was 22,085 MW.

The actual peak demand of 21,060 MW occurred January 24, 2011.

Implementation of Operating Procedure 4 (OP 4) was not required during the winter operating period.

New York

The forecasted peak for winter 2010-11 was 24,289 MW.

The actual peak demand of 24,654 MW occurred on December 14, 2010.

No particular issues to report.

Ontario

The forecasted peak for winter 2010-11 was 22,474 MW.

The actual peak demand of 22,733 MW occurred on January 24, 2011 with a weather corrected peak of 22,695 MW. There were no issues with meeting this level of demand.

Québec

The internal demand forecast was 36,945 MW for the 2010-11 Winter Operating Period.

Actual peak demand occurred on January 24, 2011 at 8h00 EST. Internal demand was a record 37,717 MW. At that time, exports of 2,382 MW were sustained by Hydro-Québec Production. Hydro-Québec Distribution was importing 1,739 MW for its own needs and 957 MW were being wheeled through the system by other clients. Moreover, 1,570 MW of interruptible industrial load was called for the peak hour. Global system needs, accounting for interruptible load and exports were then evaluated at 38,529 MW.

Temperature in Montréal at peak was -27 °C (-17 °F) and wind velocity was 9 km/h (5.6 mph). Temperature in most other areas of the province was below -30 °C (-22 °F). Winter 2010-11 was slightly warmer than average. Mean temperatures were 0.6 °C (1.0 °F) warmer than normal temperatures for that period.

Generation and Reserves

At the time of peak, maximum generation capacity either belonging to HQP or under contract with HQP and HQD was about 42,250 MW, including Churchill Falls, various firm contracts and the TransCanada (T.C.E) gas generating station.

Generation outages totaled 818 MW. T.C.E. (547 MW in winter) is still under a temporary shutdown agreement with HQD and is included in the outages. Tracy oil-fueled G.S. had one unit (150 MW) on outage (Now retired). Hydraulic, wind, and mechanical restrictions totaled 2,026 MW. Thus, total available capacity was about 39,400 MW.

Thirty-minute operating reserve at peak time was 1,960 MW, 460 MW over the requirement. At peak time, 450 MW of capacity was called from Rio Tinto Alcan to backup the Châteauguay HVDC converter refusal to start-up. (See *Interconnections* below).

State of the System

735 kV Lines

An ice storm and wind condition occurred on the North Shore of the St. Lawrence River in early December 2010. On December 2, 2010 at 19h16 EST Line 7004 (Micoua – Laurentides) tripped-out due to an open phase (Broken jumper). This line was back in service on December 9, 2010 at 12h21 EST. On December 6 at 18h42, Line 7019 (Micoua – Saguenay) also tripped-out. At this time, two out of the five 735 kV lines on the Manicouagan – Québec Interface were out until December 7, 11h18. (Total outage of 16 hours and 36 minutes). This interface transfers power from the Churchill Falls and Manicouagan/Micoua generating complexes (Transfers of about 11,000 MW) to the load areas. Transfers had to be reduced according to system operating strategies. The

situation was mitigated through gas turbine start-up, utilization of imports from a neighboring Québec system, and non-firm transaction curtailments. The system was not at its peak winter load at that time.

On peak day, all 735 kV transmission was available.

Other Equipment

Synchronous Condenser CS23 at Duvernay substation was unavailable for the Winter Operating Period.

The reactive power output of generating stations in the southern part of the system at peak load and capacitor bank availability were adequate considering load and system conditions during the Winter Operating Period.

Wind generation

Approximately 448 MW of wind generation was present on the system during the peak hour on January 24 out of a total of 659 MW (68 percent).

Interconnections

On January 24 (peak day), from 6h00 to 7h00 the Massena – Châteauguay transfer was nil. Various transactions on the interconnection actually netted to zero for that hour. The HVDC converters were therefore operated at 0 MW for that period. At 7h00, the schedule called for imports on the interconnection, but the converters refused to start-up. Back-up imports of 450 MW were called from Rio Tinto Alcan. The cause of the problem was that adjacent station breakers became too cold and began to leak air. It was shown that during extreme cold periods, the converters should not be stopped and that a minimum power should be transferred at all times. Châteauguay procedures have been reviewed and updated accordingly. All other interconnections were available at peak time. Generally, all interconnections were available during the Winter Operating period.

Historical Winter Demand Review (Pre-2012)

The table below summarizes historical non-coincident winter peaks for each NPCC Balancing Authority Area since 2000-01.

Table 10

Historical Peak Demands by Area Occurring December to March (MW)

Year	Ontario	Maritimes	New England	New York	Québec	Total NPCC Non-Coincident Demand
2000-01	23,126	4,822	20,088	23,764	30,277	102,077
2001-02	22,623	4,783	19,872	22,798	30,080	100,156
2002-03	24,158	5,376	21,535	24,454	34,989	110,512
2003-04	24,937	5,716	22,818	25,262	36,268	115,001
2004-05	24,979	5,419	22,631	25,541	34,956	113,526
2005-06	23,766	4,987	21,733	25,060	33,636	109,182
2006-07	23,935	5,593	21,640	25,057	36,251	112,376
2007-08	23,054	5,385	21,782	25,021	35,352	110,594
2008-09	22,983	5,504	21,026	24,673	37,230	111,416
2009-10	22,045	5,205	20,791	24,074	34,659	106,774
2010-11	22,733	5,252	21,060	24,654	37,717	111,416
2011-12 Forecast	22,311	5,552	22,255	24,533	37,307[9]	111,958

[9] Includes 154 MW to account for the Cornwall load provided by Hydro-Québec.

8. 2011-12 Reliability Assessments of Adjacent Regions

Reliability*First* Corporation

Executive Summary (highlights)

Demand, Capacity and Reserve Margins

The forecast winter 2011-12 coincident peak for the RFC region is 134,500 MW Net Internal Demand (NID), which is 400 MW (0.30 percent) lower then the NID of 134,900 MW forecast for the winter 2010-11. This value is based on a Total Internal Demand of 146,700 MW minus 12,200 MW from the Demand Response programs. The RFC coincident peak demand is simply the sum of the PJM, MISO and OVEC peak demands (see below Table RFC-1). PJM accounts for approximately 78 percent and MISO accounts for 22 percent of the Total Internal Demand.

TABLE RFC-1
RFC PROJECTED PEAK DEMANDS (MW)[1]
WINTER 2011-12

	DECEMBER	JANUARY	FEBRUARY
RFC Totals [2]			
TOTAL INTERNAL DEMAND	143,700	146,700	140,900
Direct Control Load Management	(200)	(200)	(200)
Interruptible Demand	(5,600)	(5,600)	(5,600)
Load as a Capacity Resource	(7,300)	(6,400)	(7,500)
NET INTERNAL DEMAND	130,600	134,500	127,600

[1] - All demand totals are rounded to the nearest 100 MW.
[2] - The RFC regional demand includes OVEC with the PJM and MISO areas of RFC.

The RFC region has 209,800 MW of capacity that has been identified as Existing, Certain for the winter 2011-12. This value is based on the Existing Capacity of 232,500 MW minus Existing Inoperable of 900 MW minus Existing Other Capacity of 9,600 MW minus Demand Response of 12,200 MW (See below - Table RFC-2). When compared to the winter of 2010-11 and its forecasted Existing Certain Capacity of 214,900 MW there is a decrease of 5,100 MW for the winter 2011-12.

Capacity resources committed to the markets at the beginning of the winter period are assumed constant throughout the winter. New capacity that is in-service after the start of the planning year (June) is not included within the calculation of the winter reserve margins for either PJM or MISO.

TABLE RFC-2
RFC PROJECTED CAPACITY RESOURCES (MW)
WINTER 2011-12

	RFC
Capacity as of January 1, 2012	
EXISTING CAPACITY	232,500
EXISTING INOPERABLE	(900)
EXISTING OTHER CAPACITY	(9,600)
DEMAND RESPONSE (incl. Load as a Capacity Resource)	(12,200)
EXISTING CERTAIN CAPACITY	209,800
CAPACITY TRANSACTIONS - IMPORTS [1]	5,300
CAPACITY TRANSACTIONS - EXPORTS [1]	(1,400)
NET INTERCHANGE	3,900
CAPACITY and NET INTERCHANGE	213,700
DEMAND RESPONSE (incl. Load as a Capacity Resource)	12,200
NET CAPACITY RESOURCES	225,900

1 - Intra-regional transfers reported by the RTOs (between RTOs and with OVEC) have been removed.

The PJM projected reserve margin for winter 2011-12 based on Net Internal Demand is 52.8 percent, which is in excess of the required reserve margin of 15.5 percent. This is a 5.2 percentage point decrease over the 2010-11 forecast reserve margin, which did not include the ATSI and DEOK demand and capacity resources. PJM is projected to have adequate reserves for the 2011-12 winter peak demand.

The reserve margin requirement calculated for MISO for the 2011-12 winter season is 17.4 percent. The projected reserve margin of 45.4 percent is based on the Net Internal Demand. Therefore, MISO is projected to have adequate reserves for the 2011-12 winter peak demand.

The projected reserve margin for the Reliability*First* (RFC) region is 79,200 MW, which is 58.9 percent based on Net Internal Demand and Net Capacity Resources without demand Response. Both Midwest ISO (MISO) and PJM RTO (PJM) have sufficient resources to satisfy their planning reserve requirements. Therefore, the resulting

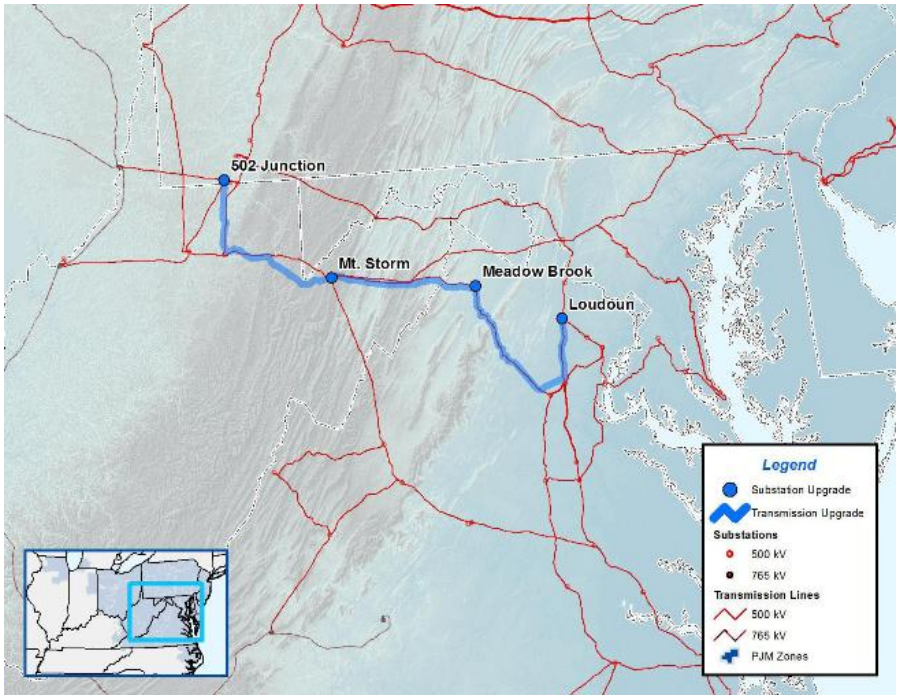
reserve margin for this winter in the Reliability*First* region is adequate. This compares to a 60.7% reserve margin in last winter's assessment.

Transmission

PJM

The TrAIL 500kV Line in the Allegheny Power/Dominion areas has increased import capability into the Baltimore/Washington/Northern Virginia area by approximately 1,000 MW (Figure 6). The AP South Interface capability is increased by approximately 500 MW. Meadowbrook to Loudoun 500 kV line was energized on April 13, 2011. Mt. Storm to Meadowbrook 500 kV line was energized on May 13, 2011 and the 502 Junction to Mt. Storm 500 kV line was energized on May 20, 2011. The Carson-Suffolk 500 kV line in Dominion is now in service. It will strengthen transmission system to the southern Dominion area.

Figure 6: PJM TRAiL Line



In the Allegheny Power portion of FirstEnergy, two 500/230 kV transformers at the Doubs substation were replaced. A fourth 500/138 kV transformer was added at the Cabot substation. The Wylie Ridge 345/138 kV #2 transformer was replaced. In Baltimore Gas and Electric, the Waugh Chapel 500/230 kV 3-phase transformer was replaced with single phase banks. In Commonwealth Edison, a third Gooding Grove Red 345/138 kV transformer was added. In Dominion Virginia Power a second Suffolk

500/230 kV transformer was added. In PEPCO, a second Burches Hill 500/230 kV transformer was added. In AEP, a 345/138 kV transformer was added at the Don Marquis substation.

No other significant substation equipment was added since last winter. There are no concerns in meeting target in-service dates for new transmission additions.

Concerning planned transmission outages:

- Nelson-Electric Junction 345 kV (1/09/2012-4/27/2012). This outage is required to reconductor the Nelson to Electric Junction line. The Nelson-Electric Junction 345 kV line outage will have an impact on the transfer capabilities between MISO and the ComEd transmission area, especially during periods of high wind generation output. Market-to-Market redispatch between PJM and MISO will be required to control transmission loading.
- Kincaid 2102 345 kV line (1/07/2012-2/15/2012). This outage is required to raise towers and to mitigate sag violation. Kincaid Special Protection Scheme will be enabled during this outage.
- Burches Hill-Chalk Point (9/12/2011-6/01/2012). Burches Hill-Chalk Point 500 kV and New Freedom-Orchard 500 kV line outages should not have significant impact on the system reliability.
- New Freedom-Orchard (1/08/2012-2/10/2012). This outage is for clearance only to install OPGW wire, restoration time is 4 hours.

PJM does not have any transmission constraints that could significantly impact reliability. Interregional transfer capabilities are adequate and include coordination with our neighbors to include any limiting elements on their system.

MISO (Michigan)

The following projects were put in service since last winter season to enable reliable and efficient transmission service for the MISO region. Ninety-six miles of new 161 kV line in ITC Midwest (ITCM) and Xcel Energy (XEL), forty miles of new 138 kV line in American Transmission Company, Michigan Electric Transmission Company (METC), and Ameren Missouri, and forty-eight miles of new 115 kV line in Minnesota and XEL have been put into service. Also, thirty-seven miles of 345 kV line outlets in Ameren Illinois connecting Prairie State Power Plant to the existing Baldwin Stallings 345 kV line were put in service in December 2010. These projects will be in areas of American Transmission Co., Ameren Missouri, Great River Energy, ITC Midwest, and Vectren. At this time no major upgrades are anticipated to come into service during the upcoming winter season. Major upgrades to MISO transmission system that have occurred since the beginning of the 2011 Summer Season (June 1, 2011) are shown in the table below. MISO does not anticipate any existing, significant transmission lines or transformers being out-of-service through the winter season. At this time it is premature to determine whether

MISO will have any transmission constraints that could significantly impact reliability. Interregional transmission transfers are not available at this time.

Table RFC-3: Recent Transmission Upgrades[10]

NERC Region	Transmission Owner	Project Name	Maximum Voltage (kV)	Project Description
MRO	XEL	Build 18 miles 115 kV line from Glencoe - West Waconia	115	Build 18 miles 115 kV line from Glencoe - West Waconia
MRO	ITCM	Glenworth 161/69kV (Glenville Area)	69-161	Construct a new 161/69kV 100 MVA substation tapping the Hayward-Worth County 161 kV line. ITC will construct the 161kV portion including the TRF and low side protection. DPC will construct the 69kV portion.
RFC	ITC	B3N Interconnection	220	Returns the Bunce Creek to Scott 220 kV circuit to service, and replaces the Phase Angle Regulator with 2 new phase angle regulating transformers in series
SERC	Ameren	Big River-Rockwood 138 kV	138	Big River-Rockwood 138 kV - Construct new line
MRO	XEL	G349, 37774-01. Upgrades for G349	345	G349 Upgrades: Yankee substation, Brookings Co 345/115 substation, Hazel Run 53 MVAr capacitor, Brookings-Yankee 115 kV line
RFC	METC	Tihart - Oakland (Genoa) 138kV	138	Replace all line structures and insulators.

MISO (Manitoba-Minnesota)

New transmission facilities were required to accommodate the new Wuskwatim Generating Station. These facilities include:

- A 26 mile 230 kV line from Birchtree Lake to Wuskwatim (W76B)
- An 85 mile 230 kV line from Wuskwatim to Herblet Lake (W73H)
- A second 85 mile 230 kV line from Wuskwatim to Herblet Lake (W74H)
- A 103 mile 230 kV line from Herblet Lake to Ralls Island (H75P)

For Wuskwatim, a 150 MVAr Static VAr Compensator (SVC) will be installed at the Thompson Birchtree 230 kV station to provide transient voltage support. The SVC and the Bank 1 transformer at Birchtree Station that supports the SVC will be in service by the start of the winter season.

Manitoba Hydro expects to meet the in-service dates for the Wuskwatim transmission facilities. Manitoba Hydro does not anticipate any significant transmission lines or transformers being out of service through the 2011-12 winter season. Manitoba Hydro does not foresee any transmission constraints that could significantly impact reliability.

[10] Reflects all projects that have been put into service since the start of the 2011 summer season.

There is a request of a 6 week outage to the 230 kV Circuit L20D (Oct 15th to Nov 30th, 2011). This outage will impact transfer limits for the Manitoba to USA interface. Operating guides are developed to ensure reliability of the interconnected power grid.

All Manitoba Hydro transfer capabilities with neighboring utilities are determined in accordance with NERC, Regional, and Manitoba Hydro reliability standards and criteria such that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency and specified multiple contingencies. These studies consider simultaneous transfers and transmission and generation constraints.

- **Manitoba Hydro – United States** (MH-USA) interconnecting tie line transfer limits are developed through joint studies with the Interconnected Study Working Group (ISG).
- **Manitoba Hydro – Ontario** (MH-Hydro One) interface transfer capability is determined from separate analyses conducted by Manitoba Hydro's System Performance department and by Ontario Independent Electricity System Operator (IESO) and is also coordinated with the latest analysis and guides from the Manitoba–Ontario – Minnesota (MOM) interconnection working group.
- **Manitoba Hydro – SaskPower** (MH-SP) interconnecting tie line transfer limits are developed through joint studies by the two utilities on a semi-annual (winter and summer season) basis. Analyses are conducted to determine interface transfer capabilities for the most probable operating configurations. These analyses also examine sensitivities of the transfer capabilities to variances in major network parameters on both sides of the interface.

- The BEPC/Western/Heartland Integrated System has energized several new interconnections since the 2010 winter season. In South Dakota, an 11.3 mile 230 kV line was added from Wessington Springs substation to Prairie Winds (Crow Lake). Crow Lake is a new wind farm collector site for 162 MW (108 units at 1.5 MW). The 0.6 mile White–Deer Creek 345kV line is projected to be in service December of 2011.

- Northwestern Public Service is working on completion of the new, 14 mile long, Western's Letcher Junction–NWE Mitchell Transmission Substation 115KV line. The line is currently scheduled to be in service by December of 2011. The project will provide additional support to the Mitchell, South Dakota area.

- MAPP is not aware of any transmission constraints or transmission issues that will affect system reliability (i.e., deliverability of generation to network load).

Region Description

All Reliability*First* Corporation (RFC) members, except Ohio Valley Electric Corporation (OVEC), are affiliated with either the Midwest Independent Transmission System Operator (MISO) or the PJM Interconnection (PJM) Regional Transmission Organization (RTO). OVEC, a generation and transmission company located in Indiana, Kentucky and Ohio, has arranged for Reliability Coordination (RC) service from MISO, but is not a MISO member company. Also, RFC does not have officially designated subregions. MISO and PJM each operate as a single Balancing Authority (BA) area. Since all RFC demand is in either MISO or PJM except for the small load (less than 100 MW) within the OVEC BA area, the reliability of PJM and MISO are assessed and the results used to indicate the reliability of the RFC Region.

ReliabilityFirst currently consists of 48 Regular Members, 22 Associate Members, and 4 Adjunct Members operating within 3 NERC Balancing Authorities (MISO, OVEC, and PJM), which includes over 350 owners, users, and operators of the bulk-power system. They serve the electrical requirements of more than 72 million people in a 238,000 square-mile area covering all of the states of Delaware, Indiana, Maryland, Ohio, Pennsylvania, New Jersey, and West Virginia, plus the District of Columbia; and portions of Illinois, Kentucky, Michigan, Tennessee, Virginia, and Wisconsin. The ReliabilityFirst area demand is primarily summer peaking. *(http://www.rfirst.org).*

9. CP-8 2011-12 Winter Multi-Area Probabilistic Reliabilty Assessment

EXECUTIVE SUMMARY

Introduction

This study estimated the use of NPCC Area Operating Procedures designed to mitigate resource shortages for the winter of 2011/12 (November 2011 through March 2012). The CP-8 Working Group's effort is consistent with the CO-12 Working Group's study, "*NPCC Reliability Assessment for Winter 2011-12*", November 2011. [11]

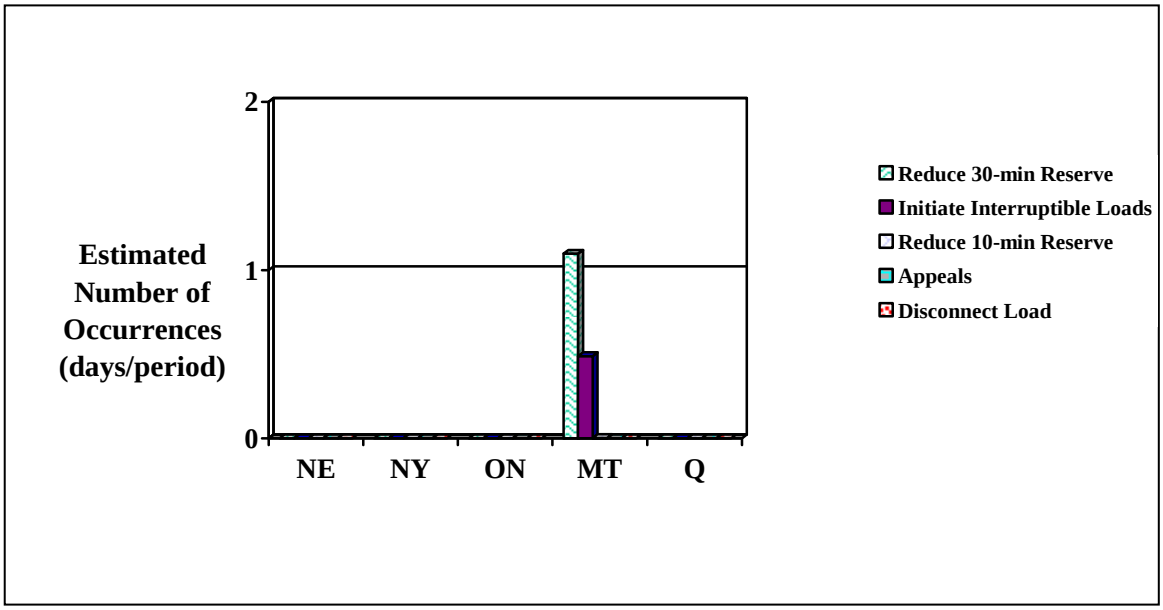
General Electric's (GE) Multi-Area Reliability Simulation (MARS) program was selected for the analysis. GE Energy was retained by NPCC to conduct the simulations.

Results

For the November 2011 - March 2012 period, Figure EX-1 shows the estimated use of the indicated operating procedures under the Base Case assumptions for the expected load level (the expected load level results were based on the probability-weighted average of the seven load levels simulated).

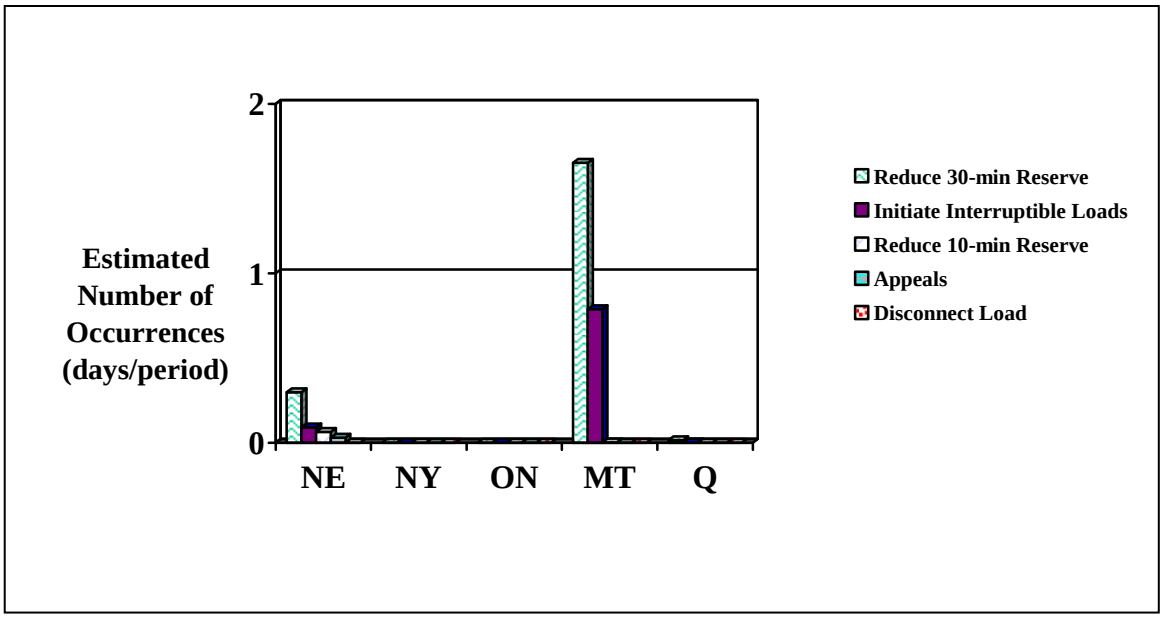
[11] See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx

Figure EX-1
Expected Use of Indicated Operating Procedures for Winter 2011/12
Base Case Assumptions – Expected Load Level



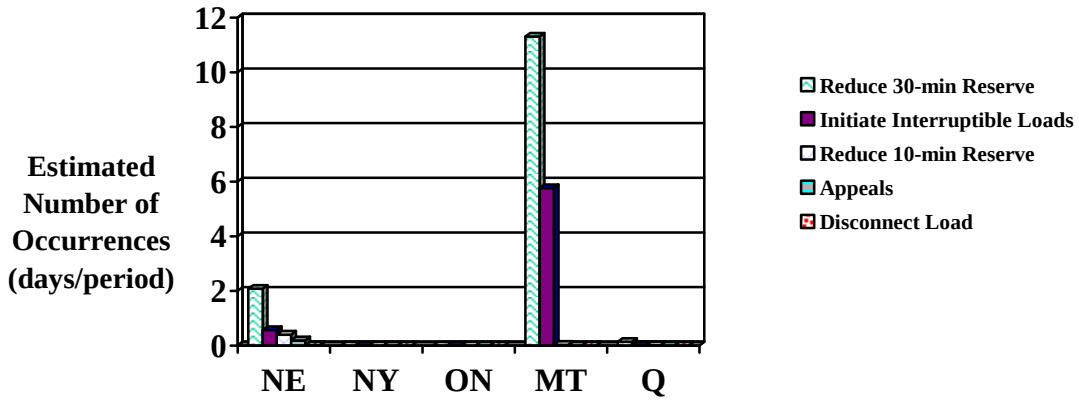
For the November 2011 - March 2012 period, Figure EX-2a shows the estimated use of the indicated operating procedures under the Severe Case assumptions for the expected load level (the expected load level results were based on the probability-weighted average of the seven load levels simulated).

Figure EX-2a
Expected Use of the Indicated Operating Procedures for Winter 2011/12
Severe Case Assumptions - Expected Load Level



For the November 2011 - March 2012 period, Figure EX-2b shows the estimated use of the indicated operating procedures under the Severe Case assumptions for the extreme load level (representing the second to highest load level, having approximately a 6% chance of being exceeded).

Figure EX-2b
Expected Use of the Indicated Operating Procedures for Winter 2011/12
Severe Case Assumptions - Extreme Load Level



Conclusions

As shown in Figures EX-1 and EX-2a, use of operating procedures designed to mitigate resource shortages is not expected for Québec, Ontario, and New York under both the assumed Base and Severe Case conditions for the expected load level. Only the Maritimes Area shows a need to reduce 30-minute reserves and to call on interruptible loads in response to a capacity deficiency this winter for these conditions. The results for the Maritimes Area are driven by the assumption of continuation of the Pt. Lepreau refurbishment outage. The use shown for New England in Figure EX-2a is not considered significant. The expected load level results were based on the probability-weighted average of the seven load levels simulated. Figure EX-2b shows the estimated use of operating procedures for the extreme load level if the severe set of resource unavailability assumptions used in this analysis occurs. The extreme load level represents the second to highest load level, having approximately a 6% chance of being exceeded. Only the Maritimes Area shows a need to reduce 30-minute reserves and to call on interruptible loads in response to a capacity deficiency this winter for these conditions. The use shown for New England in Figure EX-2b is not considered significant. The results for the Maritimes Area are driven by the assumption of continuation of the Pt. Lepreau refurbishment outage.

Appendix I – Winter 2011-12 Expected Load and Capacity Forecasts

Table AP-1 – NPCC Summary

Week Beginning Sundays	Installed Capacity MW	Purchases[1] MW	Sales[1] MW	Total Capacity[2] MW	Load Forecast MW	Demand Response MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin[3] MW
27-Nov-11	157,460	0	0	157,460	98,707	6,894	23,408	7,475	8,516	26,248
04-Dec-11	157,477	0	0	157,477	104,357	6,896	21,310	7,475	8,135	23,095
11-Dec-11	157,477	0	0	157,477	106,495	6,888	18,840	7,548	8,158	23,324
18-Dec-11	157,477	0	0	157,477	107,250	6,891	16,760	7,548	8,167	24,644
25-Dec-11	157,477	0	0	157,477	105,420	6,869	16,315	7,548	8,161	26,901
01-Jan-12	156,931	0	0	156,931	108,691	6,845	16,303	7,548	7,738	23,496
08-Jan-12	156,931	0	0	156,931	111,285	6,903	16,410	7,548	9,726	18,865
15-Jan-12	156,931	0	0	156,931	111,821	6,914	16,099	7,548	9,736	18,641
22-Jan-12	156,931	0	0	156,931	110,643	6,909	15,419	7,548	9,733	20,496
29-Jan-12	156,931	0	0	156,931	109,560	6,889	14,739	7,548	10,034	21,940
05-Feb-12	157,187	0	0	157,187	108,750	6,884	15,350	7,548	10,054	22,368
12-Feb-12	157,187	0	0	157,187	106,211	6,893	15,251	7,548	10,045	25,024
19-Feb-12	157,187	0	0	157,187	103,666	6,894	15,050	7,548	10,083	27,734
26-Feb-12	157,937	0	0	157,937	101,820	6,911	17,109	7,548	8,019	30,351
04-Mar-12	157,937	0	0	157,937	101,006	6,905	20,003	7,548	7,045	29,240
11-Mar-12	157,937	0	0	157,937	97,674	6,886	20,357	7,548	7,080	32,163
18-Mar-12	157,937	0	0	157,937	95,937	6,878	22,256	7,548	6,995	32,078
25-Mar-12	157,937	0	0	157,937	92,628	6,910	23,483	7,548	6,961	34,226
Notes										
1)	Purchases and Sales represent those contracts with Areas outside of NPCC									
2)	Total Capacity = Installed Capacity + Purchases - Sales									
3)	Net Margin = Total Capacity - Load Forecast + Interruptible Load - Known maintenance - Operating reserve - Unplanned Outage									

Table AP-2 – Maritimes

Week Beginning Sundays	Installed Capacity MW	Firm Purchases MW	Firm Sales MW	Total Capacity MW	Load Forecast MW	Demand Response MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW
27-Nov-11	7,676	0	0	7,676	4,656	378	1,317	628	273	1,181
04-Dec-11	7,676	166	0	7,842	4,719	380	1,317	628	273	1,285
11-Dec-11	7,676	166	0	7,842	5,120	372	1,317	628	273	876
18-Dec-11	7,676	166	0	7,842	5,324	375	1,317	628	273	676
25-Dec-11	7,676	166	0	7,842	5,284	353	1,317	628	273	693
01-Jan-12	7,686	166	0	7,852	5,101	329	1,332	628	273	848
08-Jan-12	7,686	166	0	7,852	5,552	387	1,332	628	273	455
15-Jan-12	7,686	166	0	7,852	5,430	398	1,332	628	273	588
22-Jan-12	7,686	166	0	7,852	5,392	393	1,332	628	273	620
29-Jan-12	7,686	166	0	7,852	5,427	373	1,364	628	273	534
05-Feb-12	7,686	166	0	7,852	5,482	368	1,364	628	273	473
12-Feb-12	7,686	166	0	7,852	5,419	377	1,364	628	273	545
19-Feb-12	7,686	166	0	7,852	5,073	378	1,364	628	273	892
26-Feb-12	7,686	166	0	7,852	4,948	395	1,362	628	273	1,037
04-Mar-12	7,686	166	0	7,852	4,866	389	1,362	628	273	1,113
11-Mar-12	7,686	166	0	7,852	4,719	370	1,362	628	273	1,241
18-Mar-12	7,686	166	0	7,852	4,616	362	1,362	628	273	1,336
25-Mar-12	7,686	166	0	7,852	4,609	394	1,362	628	273	1,375
Notes										
Purchase of 100 MW from HQ and 66 MW from NALCOR										
Purchase of 200 MW of firm energy from H.Q. during the months of January and February (released capacity from HQ but does not qualify in the NB market) .										

Table AP-3 – New England

Week Beginning Sundays	Installed Capacity MW	Firm Purchases MW	Firm Sales MW	Total Capacity MW	Load Forecast MW	Demand Response MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW
27-Nov-11	30,927	505	100	31,332	20,953	1,864	3,354	2,000	3,600	3,289
04-Dec-11	30,927	505	100	31,332	21,153	1,864	3,498	2,000	3,200	3,345
11-Dec-11	30,927	505	100	31,332	21,443	1,864	1,880	2,000	3,200	4,673
18-Dec-11	30,927	505	100	31,332	21,454	1,864	886	2,000	3,200	5,656
25-Dec-11	30,927	505	100	31,332	21,516	1,864	864	2,000	3,200	5,616
01-Jan-12	30,927	505	100	31,332	21,790	1,864	864	2,000	2,800	5,742
08-Jan-12	30,927	505	100	31,332	22,255	1,864	870	2,000	4,800	3,271
15-Jan-12	30,927	505	100	31,332	22,255	1,864	1,181	2,000	4,800	2,960
22-Jan-12	30,927	505	100	31,332	22,255	1,864	873	2,000	4,800	3,268
29-Jan-12	30,927	505	100	31,332	22,032	1,864	610	2,000	5,100	3,454
05-Feb-12	30,927	505	100	31,332	21,765	1,864	884	2,000	5,100	3,447
12-Feb-12	30,927	505	100	31,332	21,736	1,864	643	2,000	5,100	3,717
19-Feb-12	30,927	505	100	31,332	21,474	1,864	617	2,000	5,100	4,005
26-Feb-12	30,927	505	100	31,332	20,486	1,864	614	2,000	3,100	6,996
04-Mar-12	30,927	505	100	31,332	20,136	1,864	2,032	2,000	2,200	6,828
11-Mar-12	30,927	505	100	31,332	19,940	1,864	2,639	2,000	2,200	6,417
18-Mar-12	30,927	505	100	31,332	19,576	1,864	1,917	2,000	2,200	7,503
25-Mar-12	30,927	505	100	31,332	19,010	1,864	2,443	2,000	2,200	7,543

Notes

- Installed Capacity, Firm Purchases and Sales, and Interruptible Load are based on ISO-NE Forward Capacity Market (FCM) resource obligations for the 2011-2012 capacity commitment period.
- Purchases and sales consist of imports of 296 MW from Quebec and 209 MW from New York, and an export of 100 MW to New York.
- Load Forecast assumes Peak Load Exposure reported in the 2011 CELT Report.
- Interruptible Loads consist of both active and passive (energy efficiency) FCM Demand Resource obligations.
- 2,000 MW of operating reserve assumes 100% of the first largest contingency at 1,400 MW and 50% of the second largest contingency of 1,200 MW.
- Includes known maintenance as of October 7, 2011.
- Assumed unplanned outages based on historical observation of outages, with an additional 2,000 MW of outages for generation at risk due to gas supply during seven weeks in January and February

Table AP-4 – New York

Week Beginning Sundays	Installed Capacity MW	Firm Purchases MW	Firm Sales MW	Total Capacity MW	Load Forecast MW	Demand Response MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW
27-Nov-11	40,999	965	0	41,964	21,889	1,882	5,064	1,800	1,793	13,301
4-Dec-11	41,016	965	0	41,981	23,952	1,882	4,694	1,800	1,813	11,605
11-Dec-11	41,016	965	0	41,981	24,533	1,882	4,246	1,800	1,835	11,450
18-Dec-11	41,016	965	0	41,981	24,533	1,882	4,067	1,800	1,844	11,620
25-Dec-11	41,016	965	0	41,981	24,533	1,882	4,175	1,800	1,838	11,517
1-Jan-12	41,016	965	0	41,981	24,533	1,882	4,648	1,800	1,815	11,068
8-Jan-12	41,016	965	0	41,981	24,533	1,882	4,884	1,800	1,803	10,844
15-Jan-12	41,016	965	0	41,981	24,533	1,882	4,683	1,800	1,813	11,035
22-Jan-12	41,016	965	0	41,981	24,533	1,882	4,742	1,800	1,810	10,979
29-Jan-12	41,016	965	0	41,981	24,533	1,882	4,731	1,800	1,811	10,989
5-Feb-12	41,016	965	0	41,981	24,533	1,882	4,316	1,800	1,831	11,383
12-Feb-12	41,016	965	0	41,981	22,676	1,882	4,497	1,800	1,822	13,069
19-Feb-12	41,016	965	0	41,981	22,363	1,882	3,734	1,800	1,860	14,106
26-Feb-12	41,016	965	0	41,981	22,186	1,882	5,016	1,800	1,796	13,066
4-Mar-12	41,016	965	0	41,981	21,813	1,882	6,513	1,800	1,722	12,016
11-Mar-12	41,016	965	0	41,981	20,699	1,882	5,807	1,800	1,757	13,801
18-Mar-12	41,016	965	0	41,981	21,288	1,882	7,513	1,800	1,672	11,591
25-Mar-12	41,016	965	0	41,981	20,609	1,882	8,186	1,800	1,638	11,630

Notes

Negative Net Purchases values represent higher total sales out of NYCA than total purchases into NYCA

The "Sales" column is zero reflecting a net purchase, this does not mean there are zero sales.

Table AP-5 – Ontario

Week Beginning Sundays	Installed Capacity MW	Firm Purchases MW	Firm Sales MW	Total Capacity MW	Load Forecast MW	Demand Response MW	Known Maint./ Derat./Bottled Cap. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW
27-Nov-11	34,975	0	0	34,975	20,755	1,205	9,023	1,547	1,350	3,505
04-Dec-11	34,975	0	0	34,975	21,556	1,205	7,312	1,547	1,350	4,415
11-Dec-11	34,975	0	0	34,975	21,557	1,205	6,715	1,620	1,350	4,938
18-Dec-11	34,975	0	0	34,975	21,830	1,205	6,193	1,620	1,350	5,187
25-Dec-11	34,975	0	0	34,975	20,939	1,205	5,825	1,620	1,350	6,446
01-Jan-12	34,163	0	0	34,163	21,875	1,205	5,627	1,620	1,350	4,896
08-Jan-12	34,163	0	0	34,163	22,311	1,205	5,492	1,620	1,350	4,595
15-Jan-12	34,163	0	0	34,163	22,296	1,205	5,071	1,620	1,350	5,031
22-Jan-12	34,163	0	0	34,163	22,193	1,205	4,990	1,620	1,350	5,215
29-Jan-12	34,163	0	0	34,163	21,970	1,205	5,111	1,620	1,350	5,317
05-Feb-12	34,163	0	0	34,163	21,522	1,205	5,684	1,620	1,350	5,192
12-Feb-12	34,163	0	0	34,163	21,655	1,205	5,645	1,620	1,350	5,098
19-Feb-12	34,163	0	0	34,163	20,919	1,205	6,233	1,620	1,350	5,246
26-Feb-12	34,913	0	0	34,913	20,792	1,205	7,016	1,620	1,350	5,340
04-Mar-12	34,913	0	0	34,913	20,965	1,205	6,995	1,620	1,350	5,188
11-Mar-12	34,913	0	0	34,913	19,890	1,205	7,116	1,620	1,350	6,142
18-Mar-12	34,913	0	0	34,913	19,533	1,205	8,031	1,620	1,350	5,584
25-Mar-12	34,913	0	0	34,913	19,222	1,205	8,060	1,620	1,350	5,866
Notes										

Table AP-6 – Québec

Week Beginning Sundays	Installed Capacity1 MW	Firm Purchases2 MW	Firm Sales3 MW	Total Capacity MW	Load Forecast4 MW	Demand Response MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Gen./Load Uncertainties MW	Net Margin MW
27-Nov-11	42,882	0	437	42,445	30,454	1,565	4,650	1,500	1,500	5,906
04-Dec-11	42,882	0	437	42,445	32,977	1,565	4,489	1,500	1,500	3,544
11-Dec-11	42,882	0	437	42,445	33,842	1,565	4,682	1,500	1,500	2,486
18-Dec-11	42,882	0	437	42,445	34,109	1,565	4,297	1,500	1,500	2,604
25-Dec-11	42,882	0	437	42,445	33,148	1,565	4,134	1,500	1,500	3,728
01-Jan-12	43,138	775	650	43,263	35,392	1,565	3,833	1,500	1,500	2,603
08-Jan-12	43,138	775	650	43,263	36,634	1,565	3,833	1,500	1,500	1,361
15-Jan-12	43,138	775	650	43,263	37,307	1,565	3,833	1,500	1,500	688
22-Jan-12	43,138	775	650	43,263	36,270	1,565	3,483	1,500	1,500	2,075
29-Jan-12	43,138	775	650	43,263	35,598	1,565	2,923	1,500	1,500	3,307
05-Feb-12	43,394	650	650	43,394	35,448	1,565	3,102	1,500	1,500	3,409
12-Feb-12	43,394	650	650	43,394	34,726	1,565	3,102	1,500	1,500	4,131
19-Feb-12	43,394	650	650	43,394	33,836	1,565	3,102	1,500	1,500	5,021
26-Feb-12	43,394	650	650	43,394	33,408	1,565	3,102	1,500	1,500	5,449
04-Mar-12	43,394	0	437	42,957	33,226	1,565	3,102	1,500	1,500	5,194
11-Mar-12	43,394	0	437	42,957	32,426	1,565	3,434	1,500	1,500	5,662
18-Mar-12	43,394	0	437	42,957	30,925	1,565	3,434	1,500	1,500	7,163
25-Mar-12	43,394	0	437	42,957	29,178	1,565	3,433	1,500	1,500	8,911

Notes

1) Includes independant power producers, Alcan and available capacity of Churchill Falls at the Newfoundland-Québec border.

2) Purchases of 775 MW by the Québec Area in January
Purchases of 650 MW by the Québec Area in February

3) Sales of 410 MW December and March (+ losses)
Sales of 610 MW January and February (+ losses)
Sales do not include firm sale of 145 MW to Cornwall. (154 MW with losses)

4) Expected weekly internal peak load plus 154 MW for Cornwall including losses.

Appendix II – Load and Capacity Tables definitions

This appendix defines the terms used in the Load and Capacity tables of Appendix I. Individual Balancing Authority Area particularities are presented when necessary.

Installed Capacity

This is the generation capacity installed within a Reliability Coordinator area. This should correspond to nameplate and/or test data and may include temperature derating according to the Operating Period. It may also include wind generation derating.

Individual Reliability Coordinator area particularities

New England

Installed capacity is based on generator Forward Capacity Market supply obligations.

Québec

Both Hydro-Québec Production and Hydro-Québec Distribution provide capacity in Québec. For HQP, this includes its own generation, Churchill-Falls, Alcan contracts and private producers (hydraulic, wind, biomass, etc.). For HQD, this includes TransCanada Energy, biomass and wind generation.

Maritimes

This number is the maximum net rating for each generation facility (net of unit station service) and does not account for reductions associated with ambient temperature derating and intermittent output (e.g. hydro and/or wind).

Ontario

This number includes all generation registered with the IESO.

NPCC A-07

Capacity: The rated continuous load-carrying ability, expressed in MW or MVA of generation, transmission, or other electrical equipment.

Purchases

These are purchases between Reliability Coordinator areas or from outside NPCC that have firm transmission reservations to back them up.

Individual Reliability Coordinator area particularities

New England

Imports with obligations in the Forward Capacity Market are included.

New York

NY does not use the firm transmission concept.

Québec

Both long term firm purchases and short term calls for tenders are included as needed.

Maritimes

Short or long-term capacity-backed purchases would be included.

Ontario

Ontario only allows hourly transactions.

Sales

These are sales between Reliability Coordinator areas or to outside NPCC that have firm transmission reservations to back them up.

Individual Reliability Coordinator area particularities

New England

Exports with Forward Capacity Market obligations are included.

New York

NY does not use the firm transmission concept.

Québec

Firm sales and wheel throughs are included. However, in this assessment, the 145 MW contract to Cedar Rapids Transmission is not included in the sales. It is included in the Québec Balancing Area demand. This is different than what is done in the NERC seasonal assessments, where this load is considered a firm export.

Maritimes

Short or long-term capacity-backed sales would be included.

Ontario

Ontario only allows hourly transactions.

Total Capacity

Total Capacity = Installed Capacity + Purchases – Sales.

Demand Forecast

This is the total internal demand forecast for each Reliability Coordinator area as per its Demand Forecast Methodology (Appendix IV)

Demand Response

Loads that are interruptible under the terms specified in a contract. These may include supply and economic interruptible loads, Demand Response Programs or market-based programs.

Known Maintenance/Constraints

This is the reduction in Capacity caused by forecasted generator maintenance outages and by any additional forecasted transmission or by other constraints causing internal bottling within the Reliability Coordinator area. Some Reliability Coordinator areas may include wind generation derating.

Individual Reliability Coordinator area particularities

New England

Known maintenance includes all planned outages as reported on the ISO-NE Annual Maintenance Schedule.

Québec

This includes scheduled generator maintenance and hydraulic as well as mechanical restrictions. It also includes wind generation derating. It may include – usually in summer – transmission constraints on the TransÉnergie system.

Maritimes

This includes scheduled generator maintenance and ambient temperature derates. It also includes wind and hydro generation derating.

Ontario

This includes generator maintenance, derating, plus generation bottling.

Required Operating Reserve

This is the minimum operating reserve on the system for each Reliability Coordinator area.

NPCC A-07

Operating reserve: This is the sum of ten-minute and thirty-minute reserve (fully available in 10 minutes and in 30 minutes).

Individual Reliability Coordinator area particularities

New England

The required operating reserve consists of 100 percent of the first largest contingency plus 50 percent of the second largest contingency.

New York

The required operating reserve consists of 150 percent of the first largest contingency.

Québec

The required operating reserve consists of 100 percent of the largest first contingency + 50 percent of the largest second contingency, including 1,000 MW of hydro synchronous reserve distributed all over the system to be used as stability and frequency support reserve.

Maritimes

The required operating reserve consists of 100 percent of the first largest contingency plus 50 percent of the second largest contingency.

Ontario

The required operating reserve consists of 100 percent of the first largest contingency plus 50 percent of the second largest contingency.

Unplanned Outages

This is the forecasted reduction in Installed Capacity by each Reliability Coordinator area based on historical conditions used to take into account a certain probability that some capacity may be on forced outage.

Individual Reliability Coordinator area particularities

New England

Monthly unplanned outage values have been calculated based on five years of historical unplanned outage data.

Québec

This value includes a provision for frequency regulation in the Québec Balancing Authority Area, for unplanned outages and for heavy loads as determined by the system controller.

Maritimes

Monthly unplanned outage values have been calculated based on historical unplanned outage data.

Ontario

This value is a historical observation of the capacity that is on forced outage at any given time.

Net Margin

Net margin = Total capacity – Load forecast + Interruptible load – Known maintenance/Constraints – Required operating reserve – Unplanned outages

Bottled Resources

Bottled resources = Québec Net margin + Maritimes Net margin – available transfer capacity between Québec/Maritimes and Rest of NPCC.

This is used primarily only in summer. It takes into account the fact that the margin available in Maritimes and Québec exceeds the transfer capability to the rest of NPCC since Québec and Maritimes are winter peaking.

Revised net margin (NPCC Summary only)

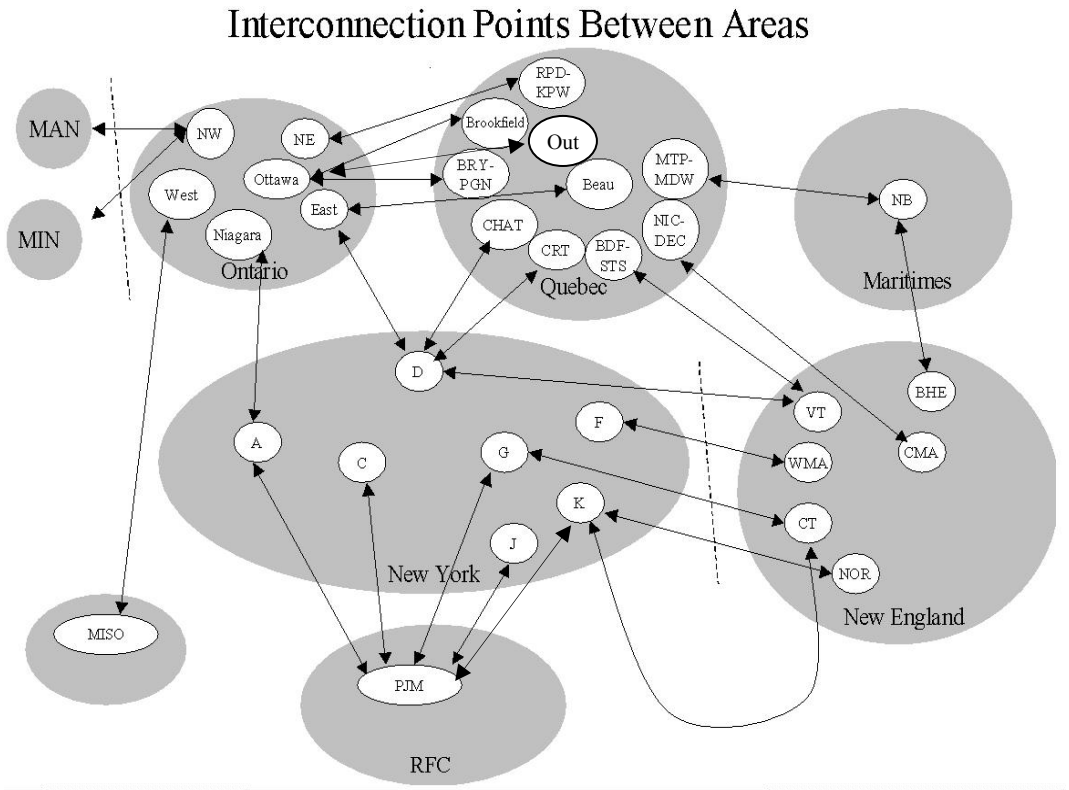
Revised net margin = Net margin – Bottled resources

This is used only in the Summer Assessment and follows from the Bottled Resources calculation.

Appendix III – Summary of Normal and Expected Feasible Transfer Capability under Winter Peak Conditions

The following table shows Normal Transfer Capability (NTC) between Reliability Coordinator areas representing transfer capabilities under normal system conditions. It is recognized that the actual transfer conditions may differ depending on system conditions or configurations such as actual voltage profiles, operating conditions, etc. Also, the Feasible Transfer Capability (FTC) values represent an expected transfer capability under the peak demand scenario with the assumed transmission configuration identified in this report. This Feasible Transfer Capability is based on historical operating experience and known operating constraints in each Reliability Coordinator area. The total for each Reliability Coordinator area represents the simultaneous transfer between Reliability Coordinator areas that may be achievable. It should be noted that real-time transfer limits may change depending on the operation of the system at the time and readers are encouraged to review information on the Available Transfer Capability (ATC) and Total Transfer Capabilities (TTC) between Reliability Coordinator areas, via http://www.nerro.org/

Diagram 1



Reliability Coordinator area Acronym Description

Maritimes		
NB	-	New Brunswick
New England		
BHE	-	Bangor-Hydro Electric
CMA	-	Central Massachusetts
VT	-	Vermont
WMA	-	Western Massachusetts
CT	-	Connecticut
NOR	-	Norwalk

Ontario		
NW	-	North West Sub-Area
West	-	Western Sub-Area
Niagara	-	Niagara
NE	-	North-East Sub-Area
CHAT	-	Ottawa
East	-	East
RFC	-	Reliability*First* Corporation
MAN	-	Manitoba
MRO	-	Midwest Reliability Organization
MIN	-	Minnesota
HAW	-	Hawthorne

New York

The New York Balancing Authority area is divided into 11 zones (A – K) that are defined based on the transmission system topology.

A	West
B	Genessee
C	Central
D	North
E	Mohawk Valley
F	Capital
G	Hudson Valley
H	Millwood
I	Dunwoodie
J	New York City
K	Long Island

Québec		
Brookfield	-	Brookfield
RPD-KPW	-	Rapide-des-Iles/ Kipawa
BRY-PGN	-	Bryson - Paugan
CHAT	-	Chateauguay
CRT	-	Cedar Rapids Transmission
BDF-STS	-	Bedford/ Stanstead
BEAU	-	Beauharnois
NIC	-	Nicolet
MTP-MDW	-	Matapedia-Madawaska
OUTA	-	Outaouais

Transfers from Maritimes to

Interconnection Point	NTC at Interconnection Points (MW)	FTC under Peak Conditions (MW)	Rationale for Constraint
Québec			
NB / MTP – MDW Lines 2101, 2102 Lines 3012/3114, 3113	335 435	335 435	Eel River winter rating is 350 MW. When Eel River converter losses and line losses to the Québec border are taken into account, Eel River to Matapédia transfer is 335 MW. Madawaska winter rating is 435 MW.
Total	**770**	**770**	
New England			
NB / BHE L3001, L3016	1,000	1,000	Transfer capability is dependent upon operating conditions in northern Maine. If key components are not in service the transfer from New Brunswick to New England will be decreased. Operation of generation in Maine may also restrict the ability for New England to import power from NB.
Total	**1,000**	**1,000**	

Transfers from New England to

Interconnection Point	NTC at Interconnection Points (MW)	FTC under Peak Conditions (MW)	Rationale for Constraint
Maritimes			
BHE / NB L3001, 3016	550	550	Transfer capability is dependent upon operating conditions in northern Maine. If key generation or capacitor banks are not operational, the transfer from New England to New Brunswick will be decreased. At the present time ISO-NE has limited the NTC to 450 MW but will increase it to 550 MW upon request from the NBSO under emergency operating conditions.
Total	**550**	**550**	
New York			
VT / D	0		
WMA / F	843		
CT / G	843		

NOR / K	200		
Sub Total	1886	1,325	Feasible Simultaneous Transfer to New York excluding Cross Sound Cable. ISO-NE planning assumptions are based on an interface limit of 1,400 MW.
CT (CSC) / K	330	330	The transfer capability of the Cross Sound Cable is 346 MW. However, losses reduce the amount of MWs that can actually be delivered across the cable. When 346 MW is injected into the cable, 330 MW is received at the point of withdrawal. The Cross Sound Cable is a DC tie and is not included in the Feasible simultaneous transfer capability with NY.
Total	**2,216**	**1,655**	
Québec			
CMA / NIC HVDC link	2,000	0	Phase 2 is required for internal Québec transmission needs at the time of peak. Capability of the facility is 2,000 MW; conditions in NE, NY & PJM may limit to 1,200 MW or less.
Highgate (VT) – Bedford (BDF) Line 1429	170	0	Capability of the facility is 225 MW, with a maximum of 220 MW deliverable to New England due to limits in Québec. At times conditions in Vermont limit the capability to 100 MW or less. The DOE permit is 170 MW.
Derby (VT) – Stanstead (STS) Line 1400	0	0	There is no capability to export to Québec through this interconnection.
Total	**2,170**	**0**	The New England to Québec transfer limit at peak load is assumed to be 0 MW. It should be noted that this limit is dependant on New England generation and could be increased up to approximately 350 MW depending on New England dispatch. If energy was needed in Québec and the generation could be secured in the Real-Time market, this action could be taken to increase the transfer limit.

Transfers from New York to

Interconnection Point	NTC at Interconnection Points (MW)	FTC under Peak Conditions (MW)	Rationale for Constraint
New England			
D / VT			
F / WMA			
K / CT			
K / NOR			
Sub Total	**1,850**	**1,850**	Feasible Simultaneous Transfer to New England excluding Cross Sound Cable.
K / CT (CSC)	340	340	Cross Sound Cable power injection is up to 346 MW; losses reduce power at the point of withdrawal to 340 MW. The Cross Sound Cable is a DC tie and is not included in the Feasible Simultaneous Transfer capability with NY.
Total	**2,190**	**2,190**	
Ontario			
D / East Lines L33P, L34P	200	200	
A / Niagara Lines PA301, PA302, BP76, PA27	1,250	1,250	Simultaneous Transfers between Ontario and NY may be impacted by loop flows and assumes phase shifting capability of Michigan - Ontario interface is not available. Additionally, thermal limits on the QFW interface may restrict imports to lesser values when the generation in the Niagara area is taken into account. BP76 O/S.
Total	**1,450**	**1,450**	
PJM			
A / PJM			
C / PJM			
G / PJM			
J / PJM			
Total	**2,900**	**2,900**	Feasible Simultaneous Transfer to PJM on peak.
Québec			
D / Chat; L7040	1,000	1,000	
D / CRT Lines CD11, CD22	100	100	
Total	**1,100**	**1,100**	

Transfers from Ontario to

Interconnection Point	NTC at Interconnection Points (MW)	FTC under Peak Conditions (MW)	Rationale for Constraint
New York			
East / D Lines L33P, L34P	300	300	
Niagara / A Lines PA301, PA302, BP76, PA27	1,390	1,390	
Total	**1,690**	**1,690**	Simultaneous Transfers between Ontario and NY may be impacted by loop flows and assumes phase shifting capability of Michigan - Ontario interface is not available. BP76 is O/S.
MISO Michigan			
Lines L4D, L51D, J5D, B3N	2,160	2,160	
Total	**2,160**	**2,160**	Simultaneous Transfers between Michigan and Ontario may be impacted by loop flows and assumes phase shifting capability of Ontario-Michigan interface is not available.
Québec			
NE / RPD – KPW Lines D4Z, H4Z	85	85	The 85 MW reflects an agreement through the TE-IESO Interconnection Committee pending further study of available options resulting from the Outaouais Interconnection. H4Z thermal capability in winter is 110 MW.
Ottawa / BRY – PGN Lines X2Y, Q4C	140	52	Circuit Q4C is capable of transferring 140 MW less ½ of Chat Falls generation that is considered in the Québec Installed Capacity (140-88=52). There is no capacity to export to Québec through Lines P33C and X2Y.
Ottawa / Brookfield Lines D5A, H9A	110	110	Only one of H9A or D5A can be in service at any time. The 110 MW reflects the maximum load that can be transferred to Ontario from Québec (Papier Masson Inc). D5A`s transfer capability is 200 MW.
East / Beau Lines B5D, B31L	470	470	Capacity from Saunders that can be synchronized to the Hydro-Québec system.
HAW / OUTA Lines A41T , A42T	1,250	1,250	Normally Ontario will schedule up to 1,230 MW allowing for a Transmission Reliability Margin of 20 MW.
Total	**2,055**	**1,967**	

MISO Manitoba, Minnesota			
NW / MAN Lines K21W, K22W	275	275	
NW / MIN Line F3M	140	140	
Total	**415**	**415**	Feasible Simultaneous Transfer to MAPP.

Transfers from Québec to

Interconnection Point	NTC at Interconnection Points (MW)	FTC under Peak Conditions (MW)	Rationale for Constraint
Maritimes			
MTP-MDW/NB Lines 2101, 2102 Lines 3012/3114, 3113	350 + radial loads 423 + radial loads	350 + radial loads 423 + radial loads	Eel River HVDC winter rating is 350 MW plus available radial load transfers. (Radial load transfer amount is dependent on local loading and will be updated monthly: Dec - 78 MW, Jan – 85 MW, Feb – 74 MW, March – 72 MW. These values will be updated as required. Madawaska winter rating is 435 MW. When Madawaska converter losses and line losses to the New Brunswick border are taken into account, Madawaska to St-André transfer is 423 MW. (Radial load transfer amount is dependent on local loading and will be updated monthly: Dec – 157 MW, Jan – 159 MW, Feb - 138 MW, March– 137 MW. These values will be updated as required.
Total	**773 + radial loads**	**773 + radial loads**	
New England			
NIC / CMA HVDC link	2,000	1,400	Capability of the facility is 2,000 MW; actual conditions in NE, NY, PJM may lower this value. The value estimated at peak load is 1,400 MW. However Phase 2 may be required for internal Québec transmission needs at the time of peak in which case, FTC would be "zero".
Bedford (BDF) – Highgate (VT) Line 1429	220	200	Limitations on the Québec system under peak load conditions.
Stanstead (STS) – Derby (VT) Line 1400	35	35	
Total	**2,255**	**1,635**	
New York			
Chateauguay – D Line 7040	1,500	1,000	Beauharnois G.S. is used for Québec needs under peak load conditions, in which case transfer is limited to Châteauguay capacity.

CRT – D Lines CD11, CD22	325	180	Transfer limit is 325 MW less projected peak Cornwall load of 145 MW tapped off the circuit.
Total	**1,825**	**1,180**	Québec to New York transfer capability may reach 2,000 MW on an hour-ahead basis and depending on operating conditions in New York and in Québec.
Ontario			
RPD-KPW / NE Lines D4Z, H4Z	75	75	This represents Line D4Z capacity. There is no capacity to export to Ontario through Line H4Z.
BRY-PGN / Ottawa Lines X2Y, P33C, Q4C	400	232	Limitations on the Québec system under peak load conditions restrict deliveries as follows P33C - 167 MW and X2Y – 65 MW. There is no capacity to export to Ontario through Line Q4C.
Brookfield / Ottawa Lines D5A, H9A	200	200	Only one of H9A or D5A can be in service at any time. The transfer capability reflects usage of D5A. The 200 MW reflects the maximum transfer available from Québec to Ontario. D5A's transfer limit is 250 MW.
Beau / East Lines B31L, B5D	790	0	Beauharnois G.S. is used for Québec needs under peak load conditions.
OUTA / HAW Lines A41T, A42T	1,250	1,250	Normally Ontario will schedule up to 1,230 MW allowing for a Transmission Reliability Margin of 20 MW.
Total	**2,715**	**1,757**	

Note: Limitations on the Québec system under peak load conditions may be due to resource limitations as opposed to transmission limitations, so that the Feasible Transfer Capability does not necessarily correspond to the TTCs published elsewhere.

Transfers from Regions External to NPCC

Interconnection Point	Normal Transfer Capability at Interconnection Points (MW)	Feasible Transfer Capability under Peak Conditions (MW)	Rationale for Constraint
MISO (Michigan) / ONT Lines L4D, L51D, J5D, B3N	1,860	1,860	Represents a worst case scenario for the implementation of Policy on operation.
Total	**1,860**	**1,860**	Simultaneous Transfers between Michigan and Ontario may be impacted by loop flows and assumes phase shifting capability of Ontario-Michigan interface is not available.
MISO (Manitoba-Minnesota) / ONT			
NW / MAN Lines K21W, K22W	275	275	
NW / MIN Line F3M	90	90	
Total	**365**	**365**	Feasible Simultaneous Transfer to Ontario.
PJM / New York			
A			
C			
G			
J			
Total	**3,000**	**3,000**	Feasible Simultaneous Transfer to New York.

Appendix IV – Demand Forecast Methodology

Reliability Coordinator area Methodologies

Maritimes

The Maritimes Area demand is the mathematical sum of the forecasted weekly peak demands of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). As such, it does not take the effect of load coincidence within the week into account. If the total Maritimes Area demand included a coincidence factor, the forecast demand would be approximately 1 to 3 percent lower.

For the NBSO, the demand forecast is based on an End-use Model (sum of forecasted loads by use e.g. water heating, space heating, lighting etc.) for residential loads and an Econometric Model for general service and industrial loads, correlating forecasted economic growth and historical loads. Each of these models is weather adjusted using a 30-year historical average.

For Nova Scotia, the load forecast is based on a 10-year weather average measured at the major load center, along with analyses of sales history, economic indicators, customer surveys, technological and demographic changes in the market, and the price and availability of other energy sources.

For Prince Edward Island, the demand forecast uses average long-term weather for the peak period (typically December) and a time-based regression model to determine the forecasted annual peak. The remaining months are prorated on the previous year.

The Northern Maine Independent System Administrator performs a trend analysis on historic data in order to develop an estimate of future loads.

New England

ISO New England's energy model is an annual model of ISO-NE Area total energy, using real income, the real price of electricity, and weather variables as drivers. Income is a proxy for all economic activity.

The peak load model is a monthly model of the typical daily peak for each month, and produces forecasts of weekly, monthly, and seasonal peak loads over a 10 year time period. Daily peak loads are modeled as a function of energy, weather, and a time trend on weather for the summer months to capture the increasing sensitivity of peak load to weather due to the increasing cooling load.

The reference demand forecast, which has a 50 percent chance of being exceeded, is based on weekly weather distributions and the monthly model of typical daily peak. The weekly weather distributions were built using 40 years of temperature data at the

time of daily electrical peaks (for non-holiday weekdays). A reasonable approximation for "normal weather" associated with the winter peak is 7.0 °F and for the summer peak is 90.2 °F.

ISO New England's forecasting details may be found at http://www.iso-ne.com/trans/celt/fsct_detail/index.html.

New York

The 2011-12 winter forecast assumes normal weather conditions for both energy usage and peak demand. The economic outlook is derived from the New York forecast provided to the NYISO by Moody's Economy.com. Econometric models are used to obtain energy forecasts for each of the eleven zones in New York. A winter load factor is used to derive the winter peak from the annual energy forecast.

The NYISO uses a weather index that relates dry bulb air temperature and wind speed to the load response in the determination of the forecast. At the forecast load levels, a one-degree decrease in this index will result in approximately 100 MW of additional load. The expected temperature at which the New York load could reach the forecast peak is 12.9 °F (-11 °C).

Ontario

The Ontario Demand is the sum of coincident loads plus the losses on the IESO-controlled grid. Ontario Demand is calculated by taking the sum of injections by registered generators, plus the imports into Ontario, minus the exports from Ontario. Ontario Demand does not include loads that are supplied by non-registered generation. The IESO forecasting system uses multivariate econometric equations to estimate the relationships between electricity demand and a number of drivers. These drivers include weather effects, economic data and calendar variables. Using regression techniques, the model estimates the relationship between these factors and energy and peak demand. Calibration routines within the system ensure the integrity of the forecast with respect to energy and peak demand, including zone and system wide projections. IESO produces a forecast of hourly demand by zone. From this forecast the following information is available:

- hourly peak demand;
- hourly minimum demand;
- hourly coincident and non-coincident peak demand by zone;
- energy demand by zone.

These forecasts are generated based on a set of weather and economic assumptions. IESO uses a number of different weather scenarios to forecast demand. The appropriate weather scenarios are determined by the purpose and underlying assumptions of the analysis. The base case demand forecast uses a median economic

forecast and monthly normalized weather. Multiple economic scenarios are only used in longer term assessments. A quantity of price-responsive demand is also forecast based on market participant information and actual market experience.

Québec

Hydro-Québec's demand and energy-sales forecasting is Hydro-Québec Distribution's responsibility. First, the energy-sales forecast is built on the forecast from four different consumption sectors – domestic, commercial, small and medium-size industrial and large industrial. The model types used in the forecasting process are different for each sector. Basically, they are analytical models based on an end-use approach and/or econometric modeling. They rely greatly on economic-driver forecasts, demographics, consumption analysis, individual short-term forecasts of large industrial customers and various surveys. This forecast is normalized for weather conditions based on a 36-year historical analysis.

The annual energy requirements are obtained by adding transmission and distribution losses to the various end-use consumption forecasts. A monthly breakdown is then obtained by applying distribution rates to the annual energy requirements. Each end-use's monthly peak demand is then calculated using load factors. The sum of these monthly end-use peak demands is the total monthly peak demand.

The Québec peak load forecast is based on a 36-year average of temperatures (1971-2006) adjusted for a global warning effect of 0.30 °C (0.54 °F) per decade starting in 1971. Moreover, each year of historical climatic data is shifted up to ±3 days to gain information on conditions that occurred during either a weekend or a week day. Such an exercise generates a set of 252 different demand scenarios. The base case scenario is the arithmetical average of the peak hour in each of those 252 scenarios.

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. Load uncertainty is due to the inherent inability to perfectly forecast economic variable evolution, demographics, energy and inherent modeling errors. These variables impact the demand forecast.

Overall uncertainty is defined as the independent combination of climatic uncertainty and load uncertainty. This Overall Uncertainty, expressed as a percentage of standard error over the total load is similar compared to the previous reliability assessment. For the 2011-12 winter peak period, the overall uncertainty is evaluated at 1,590 MW.

TransÉnergie – the Québec system operator – then determines the Québec Balancing Authority Area forecasts using Hydro-Québec Distribution's forecasts (HQ internal demand) and accounting for agreements with different private systems within the Balancing Authority Area. The forecasts are updated on an hourly basis, within a 12-day horizon according to information on local weather, wind speed, cloud cover, sunlight incidence and type and intensity of precipitation over nine regions of the Québec Balancing Authority Area. Forecasts on a minute basis are also produced within a two day horizon. TransÉnergie has a team of meteorologists who feed the demand

forecasting model with accurate climatic observations and precise weather forecasts. Short term changes in industrial loads and agreements with different private systems within the Balancing Authority Area are also taken into account on a short term basis.

Appendix V - NPCC Operational Criteria, and Procedures

NPCC Directories Pertinent to Operations

NPCC Regional Reliability Reference Directory #1 – Design and Operation of the Bulk Power System

Description: This directory provides a "design-based approach" to ensure the **bulk power system** is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, will not result from any design **contingencies.** Includes Appendices F and G "Procedure for Operational Planning Coordination" and "Procedure for Inter Reliability Coordinator area Voltage Control", respectively.

Note-Directory #1 is presently being revised by the CP-11 "Basic Criteria Review Group".

NPCC Regional Reliability Reference Directory #2 - Emergency Operations

Description: Objectives, principles and requirements are presented to assist the NPCC **Reliability Coordinator areas** in formulating plans and procedures to be followed in an **emergency** or during conditions which could lead to an **emergency**.

NPCC Regional Reliability Reference Directory #5 – Reserve

Description: This directory provides objectives, principles and requirements to enable each NPCC Reliability Coordinator Area to provide reserve and simultaneous activation of reserve.

Note-Directory #5 is presently being revised.

NPCC Regional Reliability Reference Directory #8 - System Restoration

Description: This directory provides objectives, principles and requirements to enable each NPCC Reliability Coordinator Area to perform power system restoration following a major event or total blackout.

NPCC Regional Reliability Reference Directory # 9- Verification of Generator Gross and Net Real Power Capability

Description: This document establishes the minimum criteria to verify the Gross Real Power Capability and Net Real Power Capability of generators used to ensure accuracy of information used in the steady-state and dynamic simulation models to assess the reliability of the NPCC bulk power system.

Note-Directory #9 has been approved by the RCC and will go to NPCC member ballot.

NPCC Regional Reliability Reference Directory # 10- Verification of Generator Gross and Net Reactive Power Capability

Description: This document establishes the minimum criteria to verify the Gross Reactive Power Capability and Net Reactive Power Capability of generators used to ensure accuracy of information used in the steady-state and dynamic simulation models to assess the reliability of the NPCC bulk power system. These criteria have been developed to ensure that the requirements specified in NERC Standard MOD-025-1, "Verification of Generator Gross and Net Reactive Power Capability" are met by NPCC and its applicable members responsible for meeting the NERC standards.

Note-Directory #10 has been approved by the RCC and will go to NPCC member ballot.

NPCC Regional Reliability Reference Directory # 12-Underfrequency Load Shedding Requirements

Description: This document presents the basic criteria for the design and implementation of under frequency **load shedding** programs to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements to prevent system collapse due to load-generation imbalance.

A-10 Classification of Bulk Power System Elements

Description: This *Classification of Bulk Power System Elements* (Document A-10) provides the methodology for the identification of those elements of the interconnected NPCC Region to which NPCC **bulk power system** criteria are applicable. Each **Reliability Coordinator area** has an existing list of **bulk power system** elements. The methodology in this document is used to classify elements of the **bulk power system** and has been applied in classifying elements in each **Reliability Coordinator area** as bulk power system or non-bulk power system.

NPCC Procedures Pertinent to Operations

C-01 NPCC Emergency Preparedness Conference Call Procedures-NPCC Security Conference Call Procedures

C-04 Monitoring Procedures for Guidelines for Inter-Area Voltage Control

Description: This procedural document establishes TFCO's monitoring and reporting requirements for conformance with NPCC's Procedure for Inter-AREA Voltage Control (Document C-40).

Note- Content from this Procedure was transferred to Directory #1, Appendix G.

C-05 Monitoring Procedures for Emergency Operation Criteria

Description: This procedural document establishes TFCO's monitoring and reporting requirements for conformance with NPCC Regional Reliability Reference Directory #2 - Emergency Operations.

C-07 Monitoring Procedures for Guide for Rating Generating Capability

Description: This procedural document establishes the TFCO's monitoring and reporting requirements for conformance with the NPCC, Guide for Rating Generating Capability (Document B-9).

C-15 Procedures for Solar Magnetic Disturbances on Electrical Power Systems

Description: This procedural document clarifies the reporting channels and information available to the operator during solar alerts and suggests measures that may be taken to mitigate the impact of a solar magnetic disturbance.

C-17 Procedures for Monitoring and Reporting Critical Operating Tool Failures

The purpose of this document is to outline the reporting requirements, responsibilities and obligations of the NPCC Reliability Coordinators (RC's) in response to unforeseen critical operating tool failures.

C-35 NPCC Inter-Area Power System Restoration Reference Document

Description: This procedure provides guidance and training material to the **system operator** to manage system restoration events that affect the NPCC **Reliability Coordinator areas** and adjoining **Reliability Coordinator areas**.

C-36 Procedures for Communications during Emergencies

Description: This procedure establishes the types of communications that should take place between Reliability Coordinator area system operators and with external agencies during an emergency. It also indicates the data that should be collected during and after a major system event.

C-40 Procedures for Inter-AREA Voltage Control

Description: This Procedure provides general principles and guidance for effective inter-**Area** voltage control, consistent with the NPCC, Inc. Document A-02, "Basic Criteria for Design and Operation of Interconnected Power Systems," and applicable NERC Standards. Specific methods to implement this Procedure may vary among **Reliability Coordinator areas**, depending on local requirements. Coordinated inter-**Area** voltage control is necessary to regulate voltages to protect equipment from damage and prevent voltage collapse. Coordinated voltage regulation reduces electrical losses on the

network and lessens equipment degradation. Local control actions are generally most effective for voltage regulation. Occasions arise when adjacent **Reliability Coordinator areas** can assist each other to compensate for deficiencies or excesses of reactive power and improve voltage profiles and system security.

Note-Content from this Procedure was transferred to Directory #1, Appendix G and Directory #2 Appendix B.

C-42 Procedure for Reporting and Reviewing System Disturbances

This document establishes the procedures of the Task Force on Coordination of Operation (TFCO) for reporting and reviewing system disturbances.

C-43 NPCC Operational Review for the Integration of New Facilities

The document provides the procedure to be followed in conducting operations reviews of new facilities being added to the power system. This procedure is intended to apply to new facilities that, if removed from service, may have a significant, direct or indirect impact on another Reliability Coordinator area's inter-Area or intra-Area transfer capabilities. The cause of such impact might include stability, voltage, and/or thermal considerations.

C-44 NPCC, Inc. Regional Methodology and Procedures for Forecasting TTC and ATC

Description: This document establishes a common methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) within the NPCC Region.

Presently Under Development

NPCC Regional Reliability Reference Directory #6 – "Reserve Sharing Groups"
Description: This directory is intended to provide the framework for Regional Reserve Sharing Groups within NPCC. It will establish the requirements for these.

Appendix VI - Web Sites

Independent Electricity System Operator

http://www.ieso.ca/

ISO- New England

http://www.iso-ne.com

MAPP

http://www.mappcor.org/

Maritimes

Maritimes Electric Company Ltd.

http://www.maritimeelectric.com

New Brunswick System Operator

http://www.nbso.ca/

Nova Scotia Power Inc.

http://www.nspower.ca/

Northern Maine Independent System Administrator

http://www.nmisa.com

Midwest Reliability Organization

www.midwestreliability.org

National Oceanic and Atmospheric Administration Solar Cycle Sunspots

http://www.swpc.noaa.gov/SolarCycle/

New York ISO

http://www.nyiso.com/

Northeast Power Coordinating Council, Inc.

http://www.npcc.org/

North American Electric Reliability Corporation

http://www.nerc.com

Reliability*First* Corporation

http://www.rfirst.org

TransEnergie

http://www.hydro.qc.ca/transenergie/en/index.html

Appendix VII - References

CP-8 2010/11 Winter Multi-Area Probabilistic Reliability Assessment

NPCC Reliability Assessment for Winter 2010-11 - November 2010

Appendix VIII – CP-8 2011-11 Winter Multi-Area Probabilistic Reliability Assessment – Supporting Documentation



Northeast Power Coordinating Council, Inc.

Multi-Area Probabilistic Reliability Assessment

For
Winter 2011/12

RCC Approved

June 1, 2011

Conducted by the

NPCC CP-8 Working Group

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NPCC, Inc.

Appendix VIII - CP-8 2011/12 Winter Multi-Area Probabilistic Reliability Assessment – Supporting Documentation

CP-8 WORKING GROUP

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The CP-8 Working Group acknowledges the efforts of Messrs. Glenn Haringa, GE Energy, and Andrew Ford, PJM and thanks them for their assistance in this analysis.

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EXECUTIVE SUMMARY

Introduction

This study estimated the use of NPCC Area Operating Procedures designed to mitigate resource shortages for the winter of 2011/12 (November 2011 through March 2012). The CP-8 Working Group's effort is consistent with the CO-12 Working Group's study, "*NPCC Reliability Assessment for Winter 2011-12*", November 2011. [1]

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program was selected for the analysis. GE Energy was retained by NPCC to conduct the simulations.

Results

For the November 2011 - March 2012 period, Figure EX-1 shows the estimated use of the indicated operating procedures under the Base Case assumptions for the expected load level (the expected load level results were based on the probability-weighted average of the seven load levels simulated).

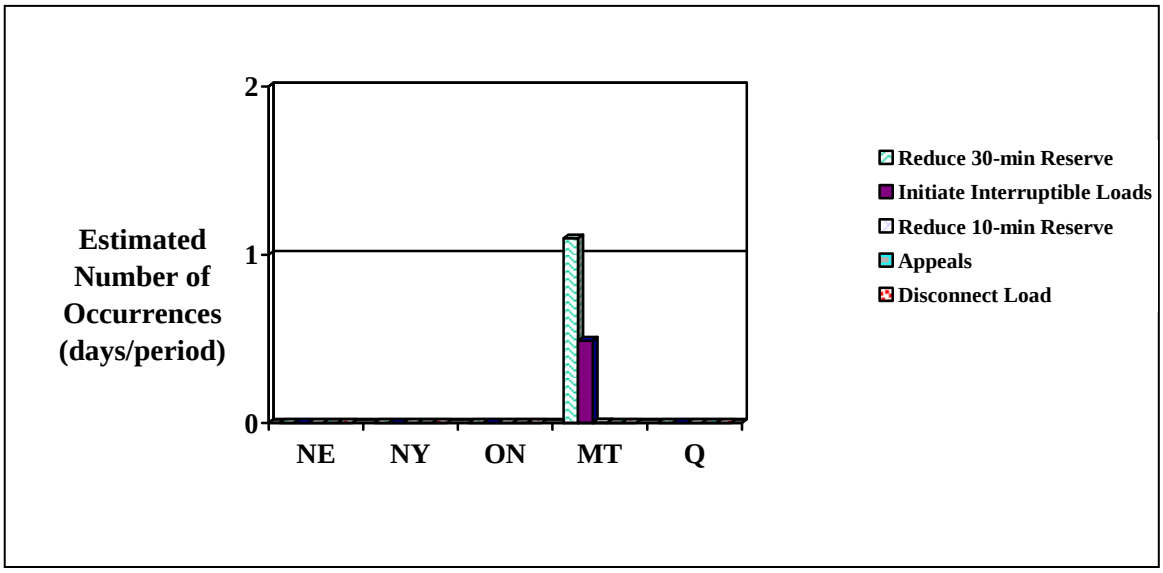


Figure EX-1
Expected Use of Indicated Operating Procedures for Winter 2011/12
Base Case Assumptions – Expected Load Level

For the November 2011 - March 2012 period, Figure EX-2a shows the estimated use of the indicated operating procedures under the Severe Case assumptions for the expected load level (the expected load level results were based on the probability-weighted average of the seven load levels simulated).

[1] See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx

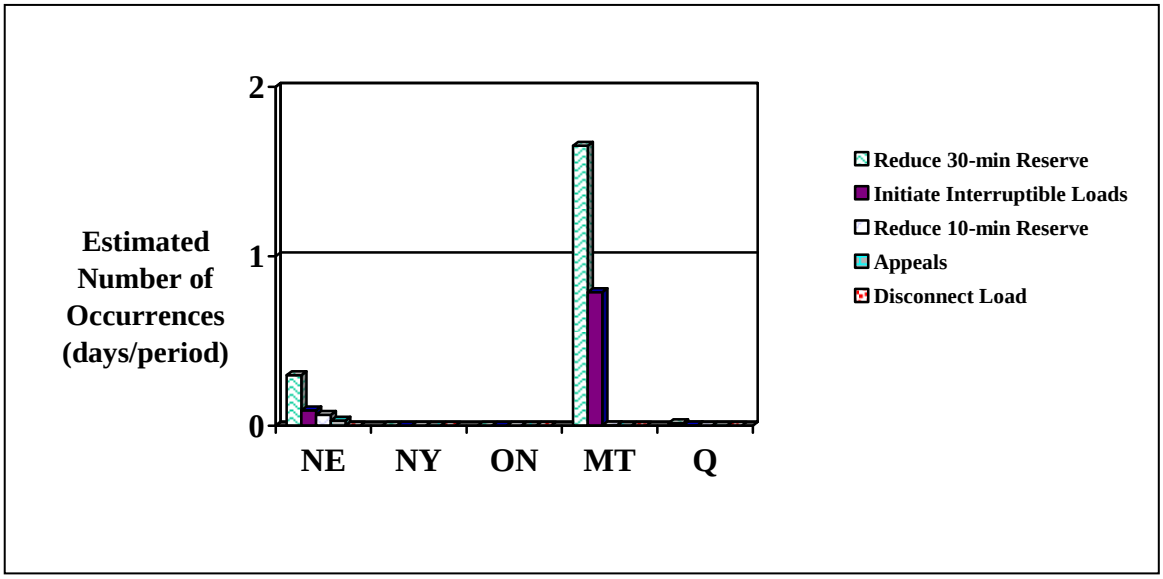


Figure EX-2a
Expected Use of the Indicated Operating Procedures for Winter 2011/12
Severe Case Assumptions - Expected Load Level

For the November 2011 - March 2012 period, Figure EX-2b shows the estimated use of the indicated operating procedures under the Severe Case assumptions for the extreme load level (representing the second to highest load level, having approximately a 6% chance of being exceeded).

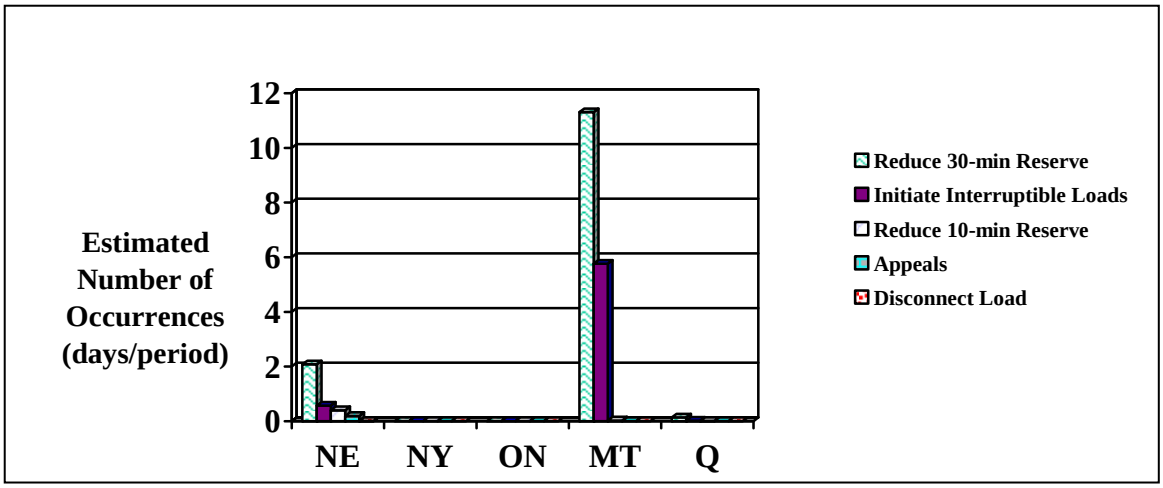


Figure EX-2b
Expected Use of the Indicated Operating Procedures for Winter 2011/12
Severe Case Assumptions - Extreme Load Level

Conclusions

As shown in Figures EX-1 and EX-2a, use of operating procedures designed to mitigate resource shortages is not expected for Québec, Ontario, and New York under both the assumed Base and Severe Case conditions for the expected load level. Only the Maritimes Area shows a need to reduce 30-minute reserves and to call on interruptible loads in response to a capacity deficiency this winter for these conditions. The results for the Maritimes Area are driven by the assumption of continuation of the Pt. Lepreau refurbishment outage. The use shown for New England in Figure EX-2a is not considered significant. The expected load level results were based on the probability-weighted average of the seven load levels simulated.

Figure EX-2b shows the estimated use of operating procedures for the extreme load level if the severe set of resource unavailability assumptions used in this analysis occurs. The extreme load level represents the second to highest load level, having approximately a 6% chance of being exceeded. Only the Maritimes Area shows a need to reduce 30-minute reserves and to call on interruptible loads in response to a capacity deficiency this winter for these conditions. The use shown for New England in Figure EX-2b is not considered significant. The results for the Maritimes Area are driven by the assumption of continuation of the Pt. Lepreau refurbishment outage.

INTRODUCTION

This study estimated the use of NPCC Area operating procedures to mitigate resource shortages for November 2011 through March 2012. The Working Group's efforts are consistent with the NPCC CO-12 Working Group's study, "*NPCC Reliability Assessment for Winter 2011-12*", November 2011. [1]

The development of this Working Group was in response to the following recommendation from the "*NPCC Reliability Assessment for Winter 2004/05*". [1]

> "The CO-12 assessment of the Summer Operating Period is accompanied by a corresponding multi area probabilistic assessment of Loss of Load Expectations and of the projected use of Operating Procedures designed to mitigate resource shortages. This assessment was not performed for this Winter Operating Period. For completeness in the assessment of the Winter Operating Period, the CO-12 Working Group recommends that TFCO and TFCP review the merits of having this assessment performed for future Winter Operating Periods."

The database developed by the CP-8 Working Group's referenced in the "*NPCC Reliability Assessment for Summer 2011*", April 2011, [2] was used as the starting point for this analysis. Working Group members reviewed the existing data and made revisions to reflect the conditions expected for the winter 2011/12 assessment period.

This report is organized in the following manner: after a brief introduction, specific model assumptions are presented, followed by an analysis of the results based on the scenarios simulated. The Working Group's Objective and Scope of Work is shown in Appendix A. Tables presenting the corresponding results for the Base Case and Severe Case simulations are listed in Appendix B. Appendix C provides an overview of General Electric's Multi-Area Reliability Simulation (MARS) Program. Version 3.07 was used for this assessment.

[2] See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx

MODEL ASSUMPTIONS

Load Representation

The loads for each Area were modeled on an hourly, chronological basis. The MARS program modified the input hourly loads through time to meet each Area's specified annual or monthly peaks and energies. Table 1 summarizes each NPCC Area's winter peak load assumptions for the winter 2011/12.

Table 1
Assumed NPCC 2011/12 Peak Loads – MW
(2003/04 Load Shapes)

	2003/04 Load Shape		
Area	**Expected Peak**	**Extreme Peak ***	**Month**
Québec* **(Q)**	37,232	39,782	January
Maritimes Area** **(MT)**	5,464	6,010	February
New England **(NE)**	22,255	23,107	January
New York **(NY)**	26,174	26,985	January
Ontario **(ON)**	22,270	23,510	January

* Extreme Peak based on load forecast uncertainty for peak month.

* ** Maritimes Area represents New Brunswick, Nova Scotia, Prince Edward Island, and the system administrated by the Northern Maine Independent System Administrator (NMISA).

Load Shape

In 2006, the Working Group considered two load shape assumptions for the winter multi-area assessment:

- a 2002/03 load shape representative of a winter weather pattern with a typical expectation of cold days; and,
- a 2003/04 load shape representative of a winter weather pattern that includes a consecutive period of cold days.

Review of the results for both load shape assumptions indicated only slight differences in the results. The Working Group agreed that the weather patterns associated with the 2003/04 load shape are representative of weather conditions that stress the system, appropriate for use in future winter assessments. Upon review of subsequent winter weather experience, the Working Group agreed that the 2003/04 load shape load shape assumption be again used for this analysis.

The growth rate in each month's peak was used to escalate Area loads to match the Area's winter demand and energy forecasts. The impacts of Demand-Side Management programs were included in each Area's load forecast.

Figure 1 shows the diversity in the NPCC area load shapes used in this analysis for the 2003/04 load shape assumptions.

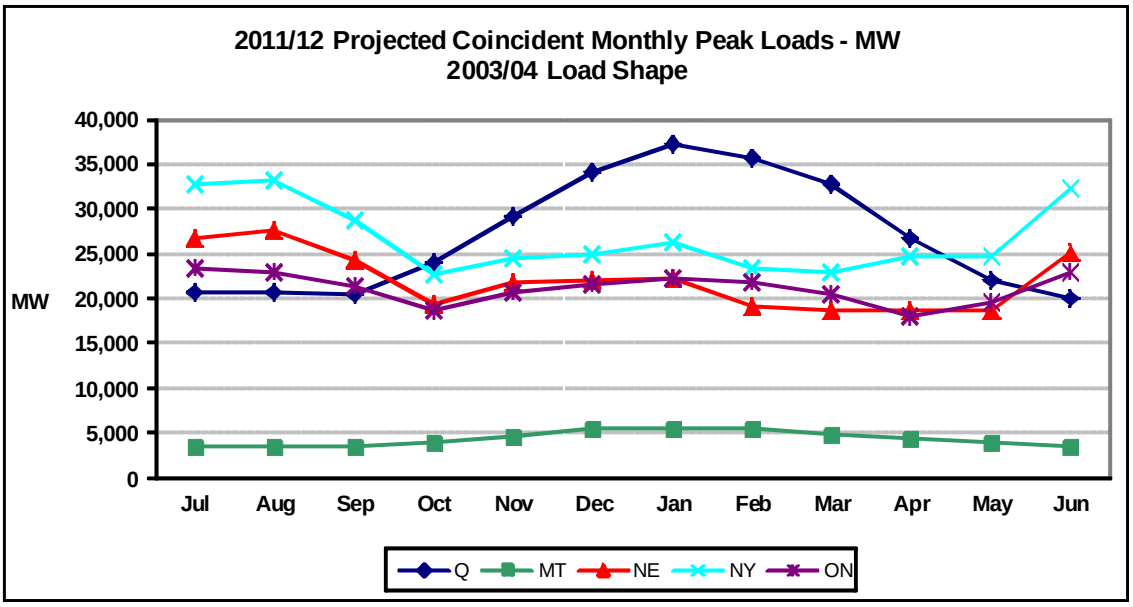


Figure 1 – 2011/12 Projected Monthly Peak Loads for NPCC Areas

(2003/04 Load Shape)

Load Forecast Uncertainty

Peak load forecast uncertainty was also modeled. The effects on reliability of uncertainties in the peak load forecast, due to weather and/or economic conditions, were captured through the load forecast uncertainty model in MARS. The program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence.

While the per unit variations in the load can vary on a monthly basis, Table 2 shows the values assumed for January 2012. Table 2 also shows the probability of occurrence assumed for each of the seven load levels modeled.

In computing the reliability indices, all of the Areas were evaluated simultaneously at the corresponding load level, the assumption being that the factors giving rise to the uncertainty affect all of the Areas at the same time. The amount of the effect can vary according to the variations in the load levels.

For this study, reliability measures are reported for two load conditions: expected and extreme. The values for the expected load conditions are derived from computing the reliability at each of the seven load levels, and computing a weighted-average expected value based on the specified probabilities of occurrence. The indices for the extreme load conditions provide a measure of the reliability in the event of higher than expected loads, and were computed for the second-to-highest load level. These values are highlighted in Table 2.

Table 2
Per Unit Variation in Load Assumed for the Month of January 2012

Area	Per-Unit Variation in Load						
Q	1.0913	1.0685	1.0456	1.0000	0.9543	0.9314	0.9086
MT	1.1000	1.1000	1.0500	1.0000	0.9500	0.9000	0.9000
NE	1.0934	1.0383	0.9971	0.9635	0.9402	0.8500	0.8000
NY	1.0430	1.0310	1.0160	0.9980	0.9750	0.9440	0.9050
ON	1.0835	1.0557	1.0278	1.0000	0.9722	0.9443	0.9165
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Generation

Tables 3(a) and 3(b) summarize the winter 2011/12 capacity assumptions for the NPCC Areas used in the analysis for the Base Case and the Severe Case Scenario, respectively. Base Case conditions are consistent with the assumptions used in the NPCC CO-12 Working Group, "*NPCC Reliability Assessment for Winter 2011-12*", November 2011.

Table 3(a)
NPCC Capacity and Load Assumptions for January 2012 - MW
Base Case - Expected Load

	Q	MT	NE	NY	ON
Assumed Capacity	38,440	7,124	30,927 [3]	41,187	29,968 [3]
Purchase/Sale	1,696	366	355	-576	0
Peak Load [4]	37,232	5,438	22,255	26,174	22,270
Demand Response (MW)	0	0	1,578	0	1,195
Reserve (%)	8	38	48	55	40
Annual Weighted Average Unit Availability (%)	98.28	89.78	89.94	84.02	83.99
Scheduled Maintenance [5]	-	687	0	3,329	1,275

Table 3 (b)
NPCC Capacity and Load Assumptions for January 2012 - MW
Severe Assumptions Scenario - Extreme Load

	Q	MT	NE	NY	ON
Assumed Capacity	37,440	6,818	30,927 [3]	40,637	29,352 [3]
Purchase/Sale	1,696	366	355	-576	0
Peak Load [4]	39,782	5,982	23,107	26,985	23,510
Demand Response (MW)	0	0	789	0	850
Reserve (%)	-2	20	39	48	28
Scheduled Maintenance [5]	-	687	0	4,359	2,102

Unit Availability

Details regarding the NPCC Area's assumptions for generator unit availability are described in the respective Area's most recent "*NPCC Comprehensive Review of Resource Adequacy*" [6] In addition, the following Areas provided the following:

[3] Does not include demand-side resources

[4] Based on the 2003/04 Load Shape assumption; internal Québec load shown - 37,005 MW including exports.

[5] Maintenance shown is for the week of the monthly peak load. Capacity shown for Québec adjusted for scheduled maintenance and other restrictions.

[6] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

Québec
The planned outages for the winter period are reflected in this assessment. The volume of planned outages is consistent with historical volumes.

Ontario
Ontario's generating unit availability was based on IESO "18-Month Outlook: An Assessment of the Reliability and Operability of the Ontario Electricity System from June 2011 – November 2012" (published May 24, 2011). [7]

Ontario market participants provided the majority of generation data. Forced Outage Rates (F.O.R.) and Planned Outage Rates (P.O.R.) were based on forecast values for generating units, which reflect past experience and future expectations based on recent maintenance activities. However, for some of the generating units F.O.R. and P.O.R. values were based on North American Reliability Council (NERC) Generator Availability Data System [8] (GADs) data for similar type units.

New England
This probabilistic assessment reflects New England generating unit availability assumptions based upon historical performance over the prior five-year period. Unit availability modeled reflects the projected scheduled maintenance and forced outages. Individual generating unit maintenance assumptions are based upon each unit's historical five-year average of scheduled maintenance. Individual generating unit forced outage assumptions were based on the unit's historical data and North American Reliability Council (NERC) average data for the same class of unit. A more detailed description of the modeling assumptions can be found by referring to the corresponding FERC filings concerning the ISO-New England Installed Capacity Requirement and related values for the 3rd Reconfiguration Auction for the 2011/2012 Capability Year. [9]

New York
Detailed availability assumptions used for the New York units can be found in the New York ISO Technical Study Report [10] - "*Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2011 – 2012 Capability Year*" and the "*New York Control Area Installed Capacity Requirement for the Period May 2011 – April 2012*" New York State Reliability Council, December 10, 2010 report.[11]

[7] See: http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2011may.pdf
[8] See: http://www.nerc.com/page.php?cid=4|43
[9] See: http://www.iso-ne.com/regulatory/ferc/filings/2010/dec/er11-2281-000_12-01-09_icr_2011-2012_ara.pdf
[10] See: http://www.nyiso.com/public/markets_operations/services/planning/planning_studex.jsp
[11] See: http://www.nysrc.org/pdf/Reports/2011%20IRM%20Report%20-%20Final%2012-10-10[1].pdf

Transfer Limits

Figure 2 depicts the system that was represented in this Assessment, showing Area and assumed Base Case transfer limits for the winter 2011/12 period. New York Area internal transmission representation was consistent with the assumptions used in the New York ISO report [10] - "*Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2011 – 2012 Capability Year*" and the "*New York Control Area Installed Capacity Requirements for the Period May 2011 – April 2012*" New York State Reliability Council, December 10, 2010 report. [11]

The New England internal transmission representation is consistent with assumptions currently being developed for the 2011 New England Regional System Plan. [12]

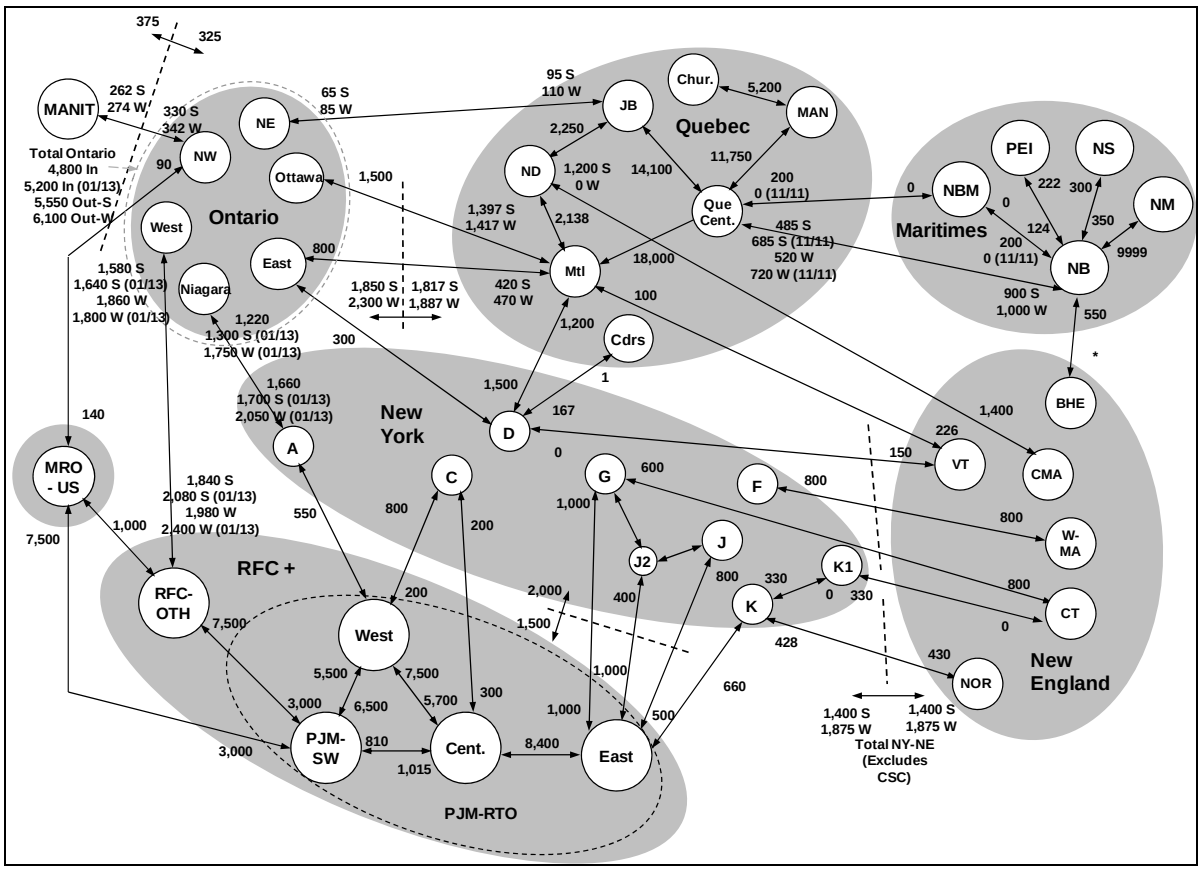


Figure 2 - Assumed Transfer Limits Between Areas

* The transfer capability from New Brunswick to New England is 1,000 MW. However, in this assessment it was assumed to be 700 MW, reflecting limitations imposed by internal New England constraints that are currently under review by ISO New England.

[12] The New England Regional System plans can be found at: http://www.iso-ne.com/trans/rsp/2009/index.html

Tie transfer limits between Areas are indicated in Figure 2 with seasonal ratings (S- summer, W- winter) where appropriate. The acronyms and notes used in Figure 2 are defined as follows:

Chur.	- Churchill Falls	NOR	- Norwalk – Stamford	RFC	- Reliability*First* Corp.
MANIT	- Manitoba	BHE	- Bangor Hydro Electric	NB	- New Brunswick
ND	- Nicolet-Des Cantons	Mtl	- Montréal	PEI	- Prince Edward Island
JB	- James Bay	C MA	- Central MA	CT	- Connecticut
MAN	- Manicouagan	W MA	- Western MA	NS	- Nova Scotia
NE	- Northeast (Ontario)	NBM	- Millbank	NW	- Northwest (Ontario)
MRO	- Midwest Reliability Organization	VT	- Vermont	CSC	- Cross Sound Cable
NM	- Northern Maine	Que Centre	- Québec Centre		

Phase angle regulators (PARs) are installed on all four of the Ontario – Michigan interconnections. One PAR, on Keith to Waterman 230 kV circuit J5D, has been in service and regulating since 1975. The other three available PARs, on the Lambton to St. Clair 230 kV (circuit L51D), the 345 kV circuit L4D and the Scott-Bunce Creek 230 kV (circuit B3N) remain idle. Although the operating agreements are now ready, the completion of the filing process with FERC and the Department of Energy may delay the in-service date for the remaining PARS until after the summer period. Although they are currently bypassed, these PARs can be placed in service and operated to control flows during emergency conditions.

Operating Procedures to Mitigate Resource Shortages

Each Area takes defined steps as their reserve levels approach critical levels. These steps consist of those load control and generation supplements that can be implemented before firm load has to be actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reduced operating reserves.

The need for an Area to begin these operating procedures is modeled in MARS by evaluating the daily Loss of Load Expectation (LOLE) at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

Table 4 summarizes the load relief assumptions modeled for each NPCC Area. The Working Group recognizes that Areas may invoke these actions in any order, depending on the situation faced at the time; however, it was agreed that modeling the actions as in the order indicated in Table 4 was a reasonable approximation for this analysis.

Table 4 - NPCC Operating Procedures to Mitigate Resource Shortages
2011/12 Winter Load Relief Assumptions - MW

Actions	Q	MT	NE	NY	ON
1. Curtail Load / Utility Surplus	1,073	0	0	0	315
Appeals	0	0	0	0	1.00%
RT-DR / SCR / EDRP	0	0	495 *	186*	0
SCR Load / Man. Volt. Red.	0	0	0	4.93%	0
2. No 30-min Reserves	500	162	600	600	473
3. Voltage Reduction	250	0	322	1.49%	0
Interruptible Load **	0	371	0	0	0
4. No 10-min Reserves	750	467	0	0	1,080
RT-EG	0	0	323 *	0	0
Appeals / Curtailments	0	0	0	188	0
5. 5% Voltage Reduction	0	0	0	0	2.60%
No 10-min Reserves	0	0	1,200	1,200	0

* Value modeled based on historical performance.
** Interruptible Loads for Maritimes Area (implemented only for the Area), Voltage Reduction for all others.

Assistance Priority

With the exception of the Millbank units, excess reserves and operational assistance were allocated among all of the Areas and sub-Areas with deficiencies in proportion to their deficiencies. The Millbank Station, although located within the Maritimes, has two of its units contracted to Québec. These units are modeled as a resource for Québec first, to reflect their priority order of assistance. If not required by Quebec, their output is then made available to the Maritimes. This contract was modeled as ending on October 31, 2011.

Modeling of Neighboring Regions

For the scenarios studied, a detailed representation of RFC (Reliability*First* Corp.) and the MRO-US (Midwest Reliability Organization – US portion) was modeled. The assumptions are summarized in Table 6.

Table 6
PJM, RFC-OTH, and MRO 2011/12 Base Case Assumptions [13]

	PJM	RFC-OTH	MRO-US
Peak Load (MW)	128,188	71,661	28,180
Peak Month	January	December	January
Assumed Capacity (MW)	190,068	107,868	38,752
Purchase/Sale (MW)	-809	0	0
Reserve (%)	48	51	38
Weighted Unit Availability (%)	87.48	86.37	87.64
Operating Reserves (MW)	3,400	2,206	1,700
Curtailable Load (MW)	3,257	2,000	1,666
No 30-min Reserves (MW)	2,765	1,470	1,200
Voltage Reduction (MW)	2,201	0	1,100
No 10-min Reserves (MW)	635	736	500
Appeals (MW)	400	0	200
Load Forecast Uncertainty (%)	93.81 +/- 5.33, 10.65, 15.98	94.62 +/- 4.63, 9.26, 13.88	92.79 +/- 6.20, 12.39, 18.59

Figure 3 shows the 2011/12 Projected Monthly Expected Peak Loads for NPCC, PJM, RFC-OTH (Other) and the MRO for the 2003/04 Load Shape assumption.

[13] Load and capacity assumptions for ECAR based on NERC's Electricity and Supply Database (ES&D) available at: www.nerc.com/~esd/.

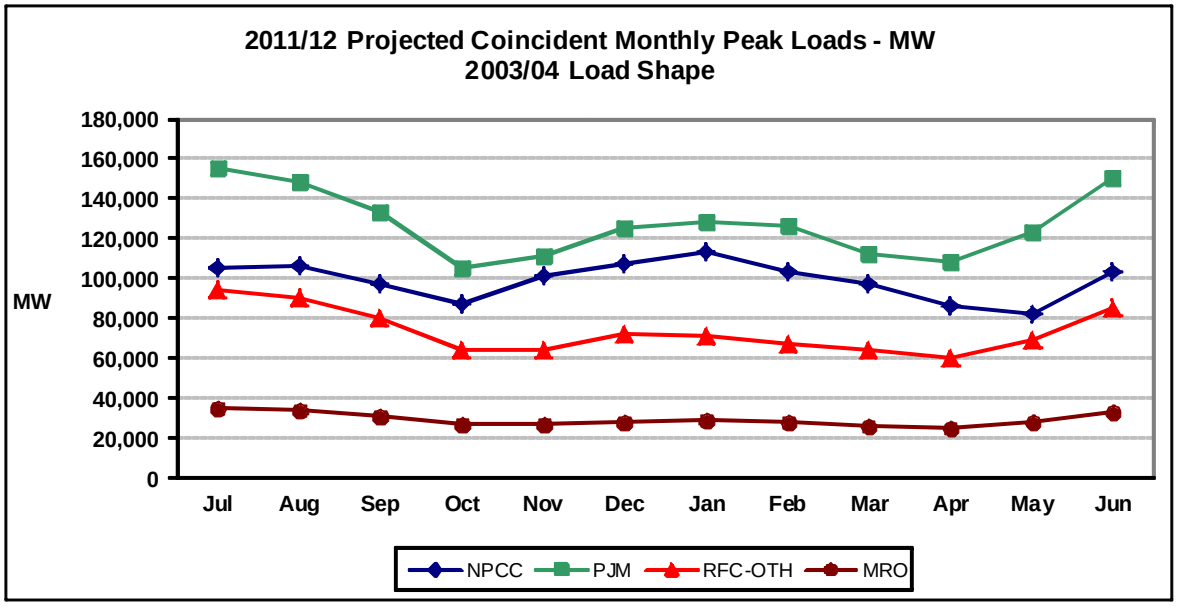


Figure 3 – 2011/12 Projected Monthly Expected Peak Loads (2003/04 Load Shape)

Reliability*First* is the successor organization to the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination (ECAR) Agreement, and the Mid-American Interconnected Network (MAIN) organizations.

The RFC-OTH (Other) area modeled in this analysis was intended to represent the non-PJM RTO region data within RFC. The modeling of the RFC region is in transition due to changes in the regional boundaries between RFC, MRO, and SERC. This model was based on publicly available data from the NERC *Electricity Supply & Demand* (ES&D), provided by PJM. The modeling of RFC-OTH is expected to evolve for future studies as data reflecting the new regional boundaries becomes available. For now, the RFC-OTH area is the non-PJM RTO region that was formerly in either MAIN or ECAR. The MAIN and ECAR boundaries do not correctly define the new RFC boundaries, but this definition insures consistency within the use of the NERC ES&D data.

WINTER 2010/11 SUMMARY

Major Weather Highlights [14]

Surface air temperatures were very warm across Canada during 2010, a feature that prevailed during all seasons and dominated the pattern of North American temperatures throughout the year. The noteworthy features over the contiguous United States were the much below normal temperatures over the southern and eastern states in the first and latter portions of 2010 which book-ended record high temperatures in those same regions during the warm half of the year.

January-March 2010 conditions were especially noteworthy for the widespread greater than +3°C departures that consumed all Canadian provinces from the Pacific to the Atlantic coast; statistics compiled by Environment Canada indicated that winter 2010 was the warmest in Canada since records began in 1948. For the period November 2010 through April 2011, the weather in Ontario was generally colder than normal. The contrast with cold winter conditions over the United States was especially striking, with up to -3°C departures over the Gulf Coast regions.

The following seasons showed a remarkable reversal in U.S. surface temperature conditions even while Canada remained consistently warm; April-September 2010 was very warm across the eastern U.S. and cold across the West. As a further testament to intense seasonal temperature variability over the U.S., Fall 2010 saw a sharp turn to cold conditions in the East and Gulf Coast while Canada remained unusually mild yet again In many ways, the pattern of Fall 2010 North American temperatures reprised the prior winter pattern.

Load Comparison

Table 7 compares NPCC Area's actual 2010-11 winter peak demands against the forecast assumptions. Except for Québec, the moderate winter temperatures, coupled with the on-going economic recession and implementation of conservation programs resulted in less demand than forecast for all NPCC sub regions for the winter of 2010-11.

[14] See: http://www.esrl.noaa.gov/psd/csi/images/NA_sfcT_2010_SOCR_FINAL.pdf

Table 7
Comparison of NPCC 2010/11 Actual and Forecast Peak Loads – MW

	Date	Actual (MW)	Forecast (Based on 2003/04 Load Shape)		
Area			**Expected Peak**	**Extreme Peak**	**Month**
Québec	Jan. 24, 2011	37,717	36,367	39,204	January
Maritimes Area	Jan. 24, 2011	5,375	5,430	5,973	February
New England	Jan. 24, 2011	21,060	22,085	22,931	January
New York	Dec. 14, 2010	24,654	28,126	28,998	January
Ontario	Jan. 24, 2011	22,733	22,848	24,010	January

Québec

The 2010/2011 winter hourly Internal Peak Demand was 37,717 MW occurring on January 24, 2011 at hour ending 08:00 EST, which established a new Québec all-time winter Internal Peak Demand. The temperature in Montréal was -27 °C (-16.6°F). Demand Response consisting of two interruptible load programs – dedicated to large and medium-sized industrial loads – was fully in use at the time of the peak. The two programs provided 1,570 MW of load relief. Therefore, Served Internal Demand was 36,147 MW. During the peak, Hydro-Québec Production exported about 2,000 MW to neighboring NPCC sub regions while Hydro-Québec Distribution imported 1,739 MW for its own load. About 957 MW were being wheeled through the system by third parties. Operating Reserve Margin requirements were met at all times. No firm load or firm transactions were affected in any way during the winter period.

No extreme issues occurred during the actual peak but some operating issues did occur during the winter period. An ice storm episode occurred in early December 2010, causing the trip-out of two 735-kV lines in the same corridor. An operations problem at Châteauguay HVdc converter station occurred during the peak time due to extreme cold weather.

An ice storm and wind condition occurred on the North Shore of the St. Lawrence River in early December 2010. This forced gas turbine start-up, utilization of imports from a neighboring Québec system, and non-firm transaction curtailments. No loss of firm load or firm transactions due to a bulk power system non performance occurred. Prior to the cold spell a public appeal was called by Hydro-Québec to inform customers of the

upcoming cold conditions for Monday, January 24 and Tuesday, January 25 and to reduce their consumption during peak hours. The effect was estimated at 200 MW at peak time. No firm transactions were curtailed during the Winter Operating Period.

Maritimes

The Maritimes Area load is the mathematical sum of the forecasted or actual peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator).

It was a milder than usual winter and no reliability issues occurred in the Maritime Provinces. The actual winter peak was 5,375 MW and occurred on January 24, 2011 HB 07:00 AST. The actual peak was coincident for the Maritimes sub-areas. The actual peak was approximately one percent less than the forecasted peak and can be attributed to milder than expected winter temperatures.

The Maritime Provinces did not experience any unexpected extreme or adverse weather conditions and it did not require use of its Demand Response measures.

New England

Within New England during the 2010/2011 winter period there were no major operational issues that impacted system reliability. From a weather perspective, December 2010 and January and February 2011 were all colder than normal. This "colder-than-normal" weather pushed monthly electricity consumption in New England above last year's values. During the period from Sunday January 23rd through Monday, January 24th 2011, extreme cold weather blanketed the region. The 2010/2011 actual winter peak demand of 21,060 MW [15] occurred on January 24, 2011 representing 21,616 MW if reconstituted for passive Demand Response. The reconstituted winter peak demand is 469 MW lower than the seasonal peak demand forecast of 22,085 MW.

Since no Emergency Operating Procedures (EOPs) were required during the winter peak demand day, there was no invocation of "active" or "dispatchable" demand response.

New York

The actual system coincident peak for the 2010/2011 winter was 24,654 MW which occurred on December 20, 2010 hour ending 18:00. This was lower than the forecast due to the impact of the current economic recession on electric energy consumption.

New York did not experience any significant operating issues during the winter 2010/2011 season.

[15] The weather-normalized 2010/2011 winter peak demand was 21,945 MW; represents 21,616 MW if reconstituted for passive Demand Response.

Ontario

The actual winter peak demand occurred on January 24, 2011 at hour ending 19:00 EST and was 22,733 MW. The peak day weather conditions were slightly colder than normal. The afternoon high for January 24th was -12°C (-10.4°F). The peak occurred on a Monday following a cold weekend. Temperatures moderated the following day. On a weather-corrected basis the peak was 22,695 MW.

At the time of the winter peak there was 0.2 MW of economically based demand response activated under provincial conservation and demand response initiatives.

Ontario experienced three transmission events that resulted in non-consequential (not directly connected to the faulted equipment) load loss during the winter period. In each case, a fault in the Greater Toronto Area resulted in a dispersed loss of load.

Except for these events, Ontario did not experience any other significant operating issues during the 2010/2011 winter season.

ANALYSIS
Winter 2011/12 Results

Base Case

Table 8 (see Appendix B) shows the estimated need for the indicated operating procedures (in days/period) for November 2011 through March 2012 period for the Base Case assumptions for all NPCC Areas for the 2003/04 load shape assumptions.

Figure 4(a) shows the estimated use of operating procedures occurrences for the NPCC Areas for the expected load (the expected load level results were based on the probability-weighted average of the seven load levels simulated) for the Base Case assumptions. The results indicate that only the Maritimes Area has a chance to use these procedures in response to a capacity deficiency.

Figure 4(b) shows the corresponding results for the extreme load (representing the second to highest load level, having approximately a 6% chance of being exceeded).

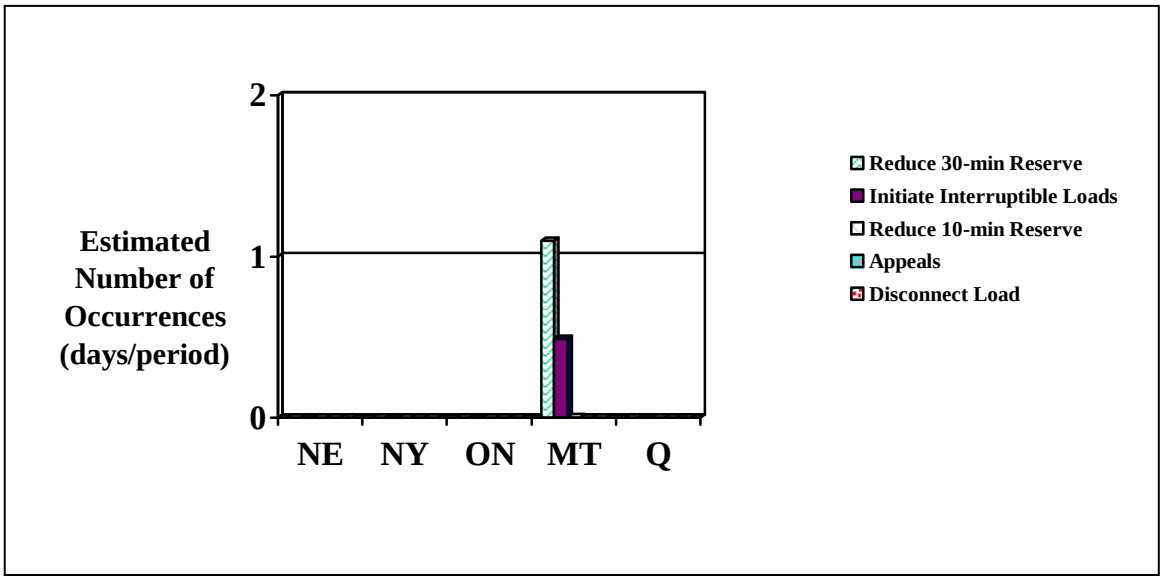


Figure 4a
Estimated Use of the Indicated Operating Procedures for Winter 2011/12
Base Case Assumptions - Expected Load Level

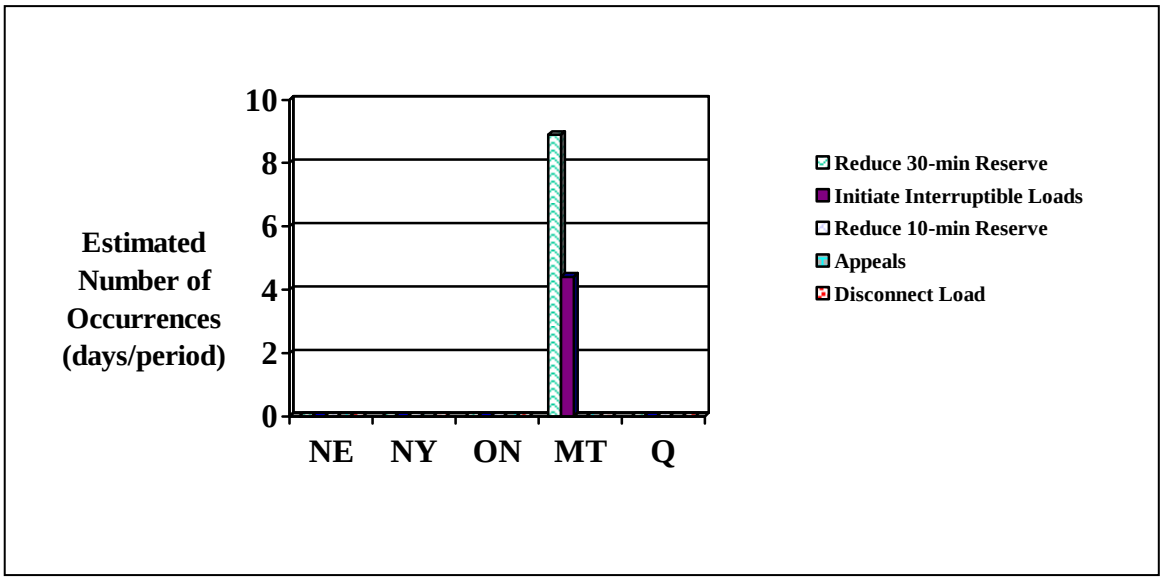


Figure 4b
Estimated Use of the Indicated Operating Procedures for Winter 2011/12
Base Case Assumptions, Extreme Load Level

The following summary of Base Case assumptions represents system conditions consistent with those assumed in the NPCC CO-12 Working Group's "*Reliability Assessment for Winter 2011-12*", November 2011. The Base Case assumptions are summarized below:

NPCC System

- ✓ As-Is System for the 2011/12 period
- ✓ Transfers allowed between Areas
- ✓ No imports from Manitoba or Minnesota
- ✓ 2003/04 Load Shape adjusted to Area's latest forecast (expected and extreme assumptions) [16]

Ontario

- ✓ Forecast consistent with the IESO "18-Month Outlook: An Assessment of the Reliability and Operability of the Ontario Electricity System from June 2011 – November 2012" (published May 24, 2011) [7]
- ✓ 1,334 MW of installed Wind Generation with wind capacity contribution of 32% at winter peak (capacity contribution factor subject to change in mid April)

[16] The 2003/04 load shape represents a weather pattern that includes a consecutive period of cold days.

- ✓ Michigan/Ontario phase shifters: PAR on J5D is in-service, PARs on circuits L4D, L51D and B3N are bypassed
- ✓ Expected conservation effects modeled
- ✓ Existing and Planned Demand Responses modeled
- ✓ Price Sensitive Demand Response (effective 1,195 MW) modeled
- ✓ Two coal units at Nanticoke (representing 950 MW) retired before winter 2011/2012
- ✓ Niagara – New York interconnection: Limits reduced for circuit BP-76 outage

Maritimes

- ✓ ~ 778 MW of installed wind generation (40% capacity value at peak) assumed
- ✓ Point Lepreau remains out-of-service until October 1, 2012

New England

- ✓ Only resources with a capacity supply obligation based on the outcomes of the 3rd Forward Capacity Reconfiguration Auction for 2011 are modeled. The total is about 33,196MW
- ✓ ~30,824 MW from internal generating resources
- ✓ ~1,578 MW from demand-side supply resources
- ✓ ~505 MW from external imports

New York

- ✓ All cables in service
- ✓ Assumptions consistent with the New York Installed Capacity Requirements for the Period May 2011 through April 2012

Québec

- ✓ Consistent with the 2010 Quebec Interim Review of Resource Adequacy
- ✓ No purchase from TCE in 2011-2012
- ✓ Tracy plant out of service since March 2011 (~ 600 MW)
- ✓ Two projects of wind generation are delayed and expected to be in service after the 2012 winter period (256 MW). A total of 868 MW of installed wind generation for 2011-2012 winter period (represents a net contribution of 260 MW, considering a 30% capacity contribution at peak)

PJM-RTO

- ✓ As-Is System for the 2011/12 winter period
- ✓ Consistent with PJM's 2010 Reserve Requirement Study Report [17]

[17] See: http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2010-pjm-reserve-requirement-study.ashx
[3]See: http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2010-load-forecast-report.ashx

- ✓ 2003-04 Load Shapes adjusted to the 2010 PJM load forecast report [18] & load forecast uncertainty provided by PJM
- ✓ Operating Reserve ~3,400 MW (30-min. 2,765 MW; 10-min. 635 MW)

RFC-OTH (Other)

- ✓ As-Is System for the 2011/12 winter period
- ✓ 2003-04 Load Shapes adjusted to the latest forecast & load forecast uncertainty provided by PJM
- ✓ Operating Reserve ~2,206 MW (30-min. 1,470 MW; 10-min. 736 MW)

MRO-US

- ✓ As-Is System for the 2011/12 period
- ✓ 2003-04 Load Shapes adjusted to the latest forecast & load forecast uncertainty provided by PJM
- ✓ Operating Reserve ~1,700 MW (30-min. 1,200 MW; 10-min. 500 MW)

Québec

Load management programs are discounted to reflect operational constraints such as number of interruptions per day, week or year.

Hydroelectric unit capacity is adjusted to reflect the impact of reservoir level on the head available. Unit capacity is also discounted to take into account operational restrictions such as ice cover formation, run-of the-river conditions.

New York

The Base Case assumes that the New York City and Long Island localities will meet their locational installed capacity requirements as described in the New York ISO report - "*Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2011 – 2012 Capability Year*" [10] and New York State will meet the capacity requirements described in the "*New York Control Area Installed Capacity Requirement for the Period May 2011 – April 2012*" New York State Reliability Council, December 10, 2010 report. [11]

The New York unit ratings were obtained from the "*2011 Load & Capacity Data of the NYISO*" (Gold Book [19]). All in-service New York generation resources were modeled.

[19] See:
http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2011_GoldBook_Public_Final.pdf

Special Case Resources and Emergency Demand Response Programs

Special Case Resources (SCRs) are loads capable of being interrupted on demand, and distributed generators, rated 100 kW or higher, that are not directly telemetered. SCRs are ICAP resources that only provide energy/load curtailment when activated in accordance with the NYISO Emergency Operating Manual. The Emergency Demand Response Program (EDRP) is a separate program that allows registered interruptible loads and standby generators to participate on a voluntary basis, and be paid for their ability to restore operating reserves.

For January, the New York ISO recommended that the SCR programs and voltage reduction be modeled as 4.93% of load as an operating procedure step; the EDRPs were modeled as a 188 MW operating procedure with a limit of five calls per month. The amounts modeled in other months vary proportionally to the monthly peak load.

Since customer participation in these programs varies over time, it is recognized that the actual amount of SCR/EDRP resources available for this winter may be different than the amount assumed in this study. The New York ISO believes the values modeled in this study represent a reasonable approximation for this analysis.

New England

The New England generating unit's ratings were consistent with their capacity supply obligation values based on the 3rd Reconfiguration Auction for the 2010/2011 Capability Year. [9]

Demand Response Program (DRP)

The non-dispatchable demand resources, including On-Peak, Seasonal-Peak, and Critical-Peak demand resources, are expected to provide a total of 760 MW of load relief during the peak hours. The dispatchable demand resources, including 677 MW of Real-Time Demand Resource and 426 MW of Real-Time Emergency Generation Resources, provide real time peak load relief at a request by ISO New England, during or in anticipation of expected operable capacity shortage conditions, to implement ISO-NE Operating Procedure No. 4, *Actions During a Capacity Deficiency* (OP4). These OP4 demand resources (totaling ~1,104 MW) are discounted in the assessment (to 818 MW) to account for performance based on the observed availability factors of demand response programs in the past. ISO-NE believes the values modeled in this study represent a reasonable approximation for this analysis.

Ontario

For the purposes of this study, the Base Case assumptions for Ontario are consistent with the IESO "18-Month Outlook: An Assessment of the Reliability and Operability of the Ontario Electricity System from June 2011-November 2012" (published May 24, 2011). [7] All in-service Ontario generation resources were modeled. Demand measures are assumed to be 1,195 MW for the study period.

Severe Case Scenario

Table 9 (see Appendix B) shows the estimated need for the indicated operating procedures (in days/period) during November 2011 through March 2012 period for the Severe Case Scenario for all NPCC Areas for the 2003/04 load shape assumptions, respectively. Only the Maritimes Area is expected to need to use these procedures in response to a capacity deficiency for this Scenario.

Figure 5(a) shows the estimated use of operating procedures occurrences for the NPCC Areas for the expected load (the expected load level results were based on the probability-weighted average of the seven load levels simulated) for the Severe Case assumptions.

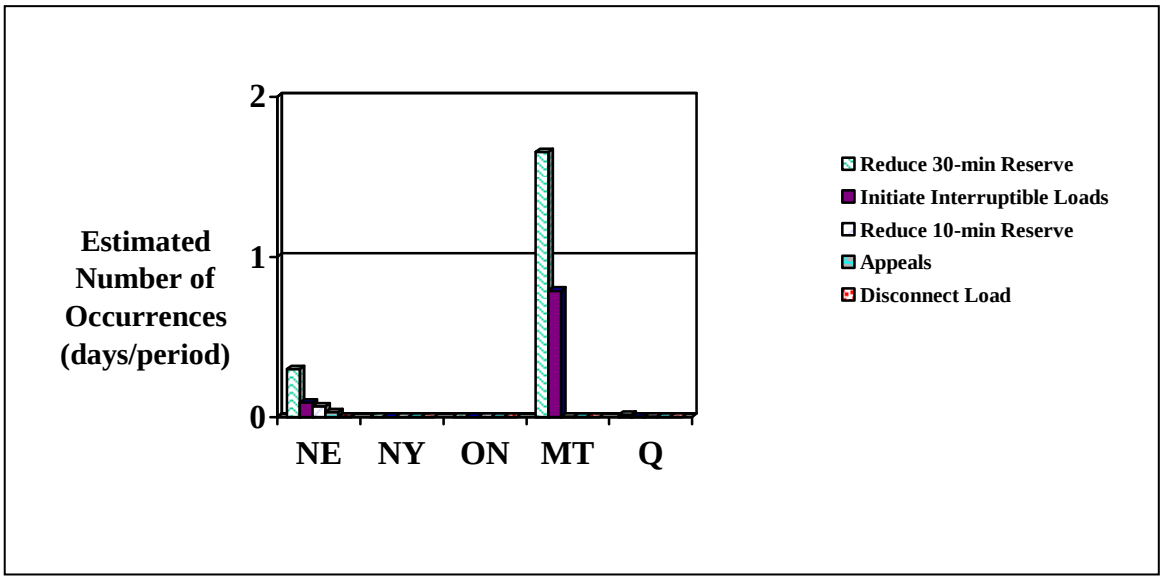


Figure 5a
Estimated Use of the Indicated Operating Procedures for Winter 2011/12
Severe Case Assumptions - Expected Load Level

Figure 5(b) shows the estimated use of the indicated operating procedures under the Severe Case assumptions for the extreme load level (representing the second to highest load level, having approximately a 6% chance of being exceeded).

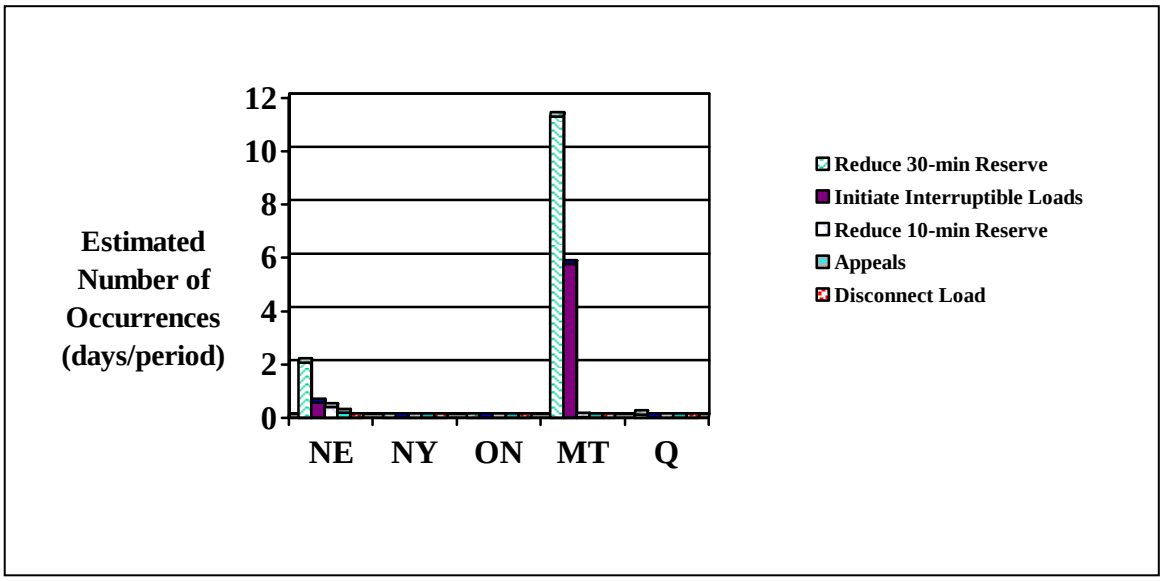


Figure 5b
Estimated Use of the Indicated Operating Procedures for Winter 2011/12
Severe Case Assumptions - Extreme Load Level

The Severe Case Scenario assumptions are summarized below:

NPCC System

- ✓ As-Is System for the 2011/12 period
- ✓ Transfers allowed between Areas
- ✓ Transfer capability between Ontario and Michigan reduced by 50%
- ✓ No imports from Manitoba or Minnesota
- ✓ 2003/04 Load Shape adjusted to Area's latest forecast (expected and extreme assumptions)

Ontario

- ✓ ~750 MW of maintenance extended into the winter period
- ✓ Only existing Demand Response modeled
- ✓ Price Sensitive Demand Response (representing an effective value of 850 MW) modeled – a 345 MW reduction
- ✓ Hydro electric capacity and energy 10% lower than the Base Case

Maritimes

- ✓ No generation capacity from wind resources in January and February
- ✓ Point Lepreau remains out-of-service until October 1, 2012

New England

- ✓ 50% reduction in Demand Response Program assumed
- ✓ Maintenance overrun by 4 weeks

New York

- ✓ 1,000 MW on extended maintenance in the Lower Hudson valley
- ✓ Astoria II generation project delayed (represents 650 MW)

Québec

- ✓ 1,000 MW reduction at Churchill Falls

PJM-RTO

- ✓ Gas-Fired only capacity not having firm pipeline transportation, assumed unavailable ~ 4,200 MW
- ✓ Increased load forecast uncertainty provided by PJM
- ✓ Ice Storm; ice blocking fuel delivery to all units. Unit Outage event ~ 8,400 MW unavailable

Conclusions

The use of operating procedures designed to mitigate resource shortages is not expected for Québec, Ontario, and New York under both the assumed Base and Severe Case conditions for the expected load level. Only the Maritimes Area shows a need to reduce 30-minute reserves and to call on interruptible loads in response to a capacity deficiency this winter for these conditions. The results for the Maritimes Area are driven by the assumption of continuation of the Pt. Lepreau refurbishment outage. The use shown for New England for these conditions is not considered significant. The expected load level results were based on the probability-weighted average of the seven load levels simulated.

Only the Maritimes Area shows a need to reduce 30-minute reserves and to call on interruptible loads in response to a capacity deficiency this winter for the extreme load level if the severe set of resource unavailability assumptions used in this analysis occurs. The use shown for New England under these conditions is not considered significant. The extreme load level represents the second to highest load level, having approximately a 6% chance of being exceeded.

The results for the Maritimes Area are driven by the assumption of continuation of the Pt. Lepreau refurbishment outage.

APPENDIX A
Objective and Scope of Work

1. Objective

Using the G.E. Multi-Area Reliability Simulation (MARS) program, review NPCC Area reliability resulting from the anticipated resource and transmission capacity reported for the 2011 – 2012 winter period under Base Case and Severe Case assumptions, and summarize the range of results for the winter and shoulder season months (the period from November 2011 to March 2012).

2. Scope

In meeting this objective, the CP-8 Working Group will review the short-term resource adequacy of NPCC and neighboring regions for the 2011 and 2012 winter period, recognizing uncertainty in forecasted demand, scheduled outages of transmission, forced and scheduled outages of generation facilities, including fuel supply disruptions, and the impact of proposed load response programs.

Reliability will be measured by calculating the estimated use of Area operating procedures used to mitigate resource shortages. The results of the assessment will be approved no later than June 2011. The assessment will:

- Review last winter's CP-8 Working Group Winter assessment with respect to actual NPCC Area's experience;
- Consider the impacts of Sub-Area transmission constraints;
- Incorporate, to the extent possible, a detailed GE MARS reliability representation for the regions bordering NPCC;
- Coordinate assessment assumptions with the NPCC Task Force on Coordination of Operations (CO-12 Working Group); and,
- Examine any impact of evolving market rules on overall NPCC interconnection assistance and other assumptions

APPENDIX B

Table 8 - Base Case Assumptions (2003/04 Load Shape Assumption) Expected Need for Indicated Operating Procedures (days/period)

(Occurrences 0.5 or greater are highlighted)

Base Case																						
	Québec				Maritimes Area				New England					New York					Ontario			
	30-min	VR	10-min	Appeal /Disc	30-min	IL	10-min	Appeal /Disc	30-min	VR	10-min	Appeal	Disc	30-min	VR	Appeal	10-min	Disc	30-min	VR	10-min	Appeal /Disc
03/04 Load Shape-Expected Load																						
Nov	-	-	-	-	0.003	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	0.611	0.245	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	-	-	-	-	0.326	0.158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	0.156	0.084	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	0.002	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	-	-	-	-	1.098	0.188	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
03/04 Load Shape-Extreme Load																						
Nov	-	-	-	-	0.044	0.008	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	5.588	2.259	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	-	-	-	-	2.036	1.452	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	1.203	0.686	0.004	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	0.020	0.008	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	-	-	-	-	8.891	4.413	0.006	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Notes: "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction ("IL" - initiate Interruptible Loads for the Maritimes Area); "10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Disc" - and disconnect customer load.

APPENDIX B

Table 9 - Severe Case Scenario (2003/04 Load Shape Assumption) - Expected Need for Indicated Operating Procedures (days/period)

(Occurrences 0.5 or greater are highlighted)

Severe Case Results	Québec					Maritimes Area					New England					New York					Ontario				
	30-min	VR	10-min	Apl	Disc	30-min	IL	10-min	Apl	Disc	30-min	VR	10-min	Apl	Disc	30-min	VR	Apl	10-min	Disc	30-min	VR	10-min	Apl	Disc
03/04 Load Shape-Expected Load																									
Nov	-	-	-	-	-	0.003	0.001	-	-	-	0.298	0.090	0.065	0.031	0.001	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	0.611	0.245	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	0.015	0.002	0.001	-	-	0.630	0.334	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	0.407	0.207	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	0.002	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	0.015	0.002	0.001	-	-	1.653	0.788	0.002	-	-	0.298	0.090	0.065	0.031	0.001	-	-	-	-	-	-	-	-	-	-
03/04 Load Shape-Extreme Load																									
Nov	-	-	-	-	-	0.044	0.008	-	-		2.078	0.569	0.399	0.184	0.006	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	5.588	2.259	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	-	0.133	0.014	0.005	-	3.860	2.191	0.005	-	-	-	-	-	-	-	-	-	-	-	-	0.001	-	-	-	-
Feb	-	-	-	-	-	1.795	1.293	0.016	0.001	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	0.020	0.008	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	-	0.133	0.014	0.005	-	11.307	5.759	0.023	0.001	0.001	2.078	0.569	0.399	0.184	0.006	-	-	-	-	-	0.001	-	-	-	-

Notes: "30-min"- reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction ("IL" - initiate Interruptible Loads for the Maritimes Area); "10-min" - and reduce 10-minute Reserve Requirement; "Apl" - and initiate General Public Appeals; "Disc" - and disconnect customer load.

APPENDIX C

Multi-Area Reliability Simulation Program Description

General Electric's Multi-Area Reliability Simulation (MARS) program [20] allows assessment of the reliability of a generation system comprised of any number of interconnected areas.

Modeling Technique

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method allows for many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies that govern system operation.

Reliability Indices

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily Loss of Load Expectation (LOLE - days/year)
- Hourly LOLE (hours/year)
- Loss of Energy Expectation (LOEE -MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating Operating Procedures (days/year or days/period)

The Working Group used both the daily LOLE and Operating Procedure indices for this analysis.

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates expected values of Loss of Load Expectation (LOLE) and can estimate each Area's expected exposure to their Emergency Operating Procedures. Scenario analysis is used to study the impacts of extreme weather conditions, variations in expected unit in-service dates, overruns in planned scheduled maintenance, or transmission limitations.

[20] See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm

APPENDIX C

Resource Allocation Among Areas

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls. The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

Generation

MARS has the capability to model the following different types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand-side management

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management impacts are modeled as load modifiers.

For each unit modeled, the installation and retirement dates and planned maintenance requirements are specified. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on either an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

APPENDIX C

Thermal Unit

In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as governed by the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

$$TR\ (A\ to\ B) = \frac{\text{Number of Transitions from A to B}}{\text{Total Time in State A}}$$

If detailed transition rate data for the units is not available, MARS can approximate the transition rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

Energy-Limited Units

Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A

APPENDIX C

Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

Cogeneration

MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-Storage and DSM

Energy-storage units and demand-side management impacts are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

Transmission System

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. The transfer limits are specified for each direction of the interface and can be changed on a monthly basis. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

Contracts

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they will be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending Area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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November 2011

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Headlines

Reserve Margins Down in Some Areas; NERC Integrated Analysis Shows Impact of Environmental Regulations on Planning Decisions, Retrofits

WASHINGTON, DC – A decrease in projected generation resources leads to declining planning reserve margins in some areas; however, a majority of areas appear to have adequate resource plans to meet projected peak demands over the next ten years, the North American Electric Reliability Corporation's (NERC) *2011 Long-Term Reliability Assessment* finds.

The annual long-term reliability assessment provides an independent, ten-year view of the electric industry by evaluating key reliability indicators, including peak demand, energy forecasts, resource adequacy, transmission development, changes in overall system characteristics and operating behavior, and other issues that may impact the reliability of the bulk power system.

"Though sufficient conceptual resource plans are in progress, for the ERCOT portion of Texas and for New England, more certainty is needed to address resource adequacy in the coming years," said Gerry Cauley, president and chief executive officer at NERC. "We will monitor these two areas in the upcoming year for progress in firming these resource projections."

Key issues and risks to bulk power system reliability identified in the long-term assessment include:

- **Reserve margins.** A decrease in projected generation resources has led to a decline in planning reserve margins in some Assessment Areas.
- **Gas-electric interdependency**. The growing dependence on natural gas as a primary fuel source of on-peak capacity must be considered in planning, and operational measures must be in place to minimize interdependency risks.
- **Variable generation.** Significant growth in wind and solar generation continues to be projected, surpassing on-peak growth forecasts of all other types of generation.
- **Demand-side management.** Increases in demand-side management continue to help offset future resource needs.
- **Transmission.** Growth is responding to increased demand for integrating and delivering new resources; construction is on pace with projections.
- **Environmental regulations.** While more flexibility is provided in some proposed rules, the cumulative effect from environmental regulations may reduce reserve margins in ways that could affect bulk power system reliability, depending on the scope and timing of final regulation implementation.

The report also provides a section that updates NERC's *2010 Special Reliability Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*. In the United States, the Environmental Protection Agency is in the process of promulgating four regulations: the proposed Coal Combustion Residuals rule, the proposed Mercury and Air Toxics Standards for Utilities, the proposed Cooling Water Intake Structures rule -316(b), and the final Cross-State Air Pollution rule.

While not all of these four regulations are final, and their effects cannot be completely measured, material changes have occurred to these regulations since NERC's 2010 assessment. While many factors affect an owner's decision to retire or retrofit a facility, NERC's analysis of the integrated impact of these regulations on planning decisions shows 36 GW in the 2018 moderate case of projected accelerated retirements and derates. Though this amount appears lower than the 2010 assessment projected, 25 GW of retirements have been announced since then and are no longer included in the projected retirement numbers. More importantly, industry information continues to show that significant retrofits will be needed over the next

four years in order to comply with proposed utility air toxics regulations.

"With MACT as the primary driver, the industry faces considerable operational challenges to complete, coordinate and schedule the necessary environmental retrofits," Cauley said. "To ensure bulk power system reliability, sufficient time and certainty to schedule retrofits of more than 500 units, as well as acquire replacement resources or prepare system reinforcements is needed."

The assessment shows five key conclusions:

- **Timing.** Compliance deadlines will challenge the electric industry's planning horizons, processes and schedules. Implementation of the proposed rules, while successfully preserving bulk power system reliability, may be highly dependent on the amount of time given to the industry to comply with future regulations, and the tools in place to support the industry's transition.
- **Regionality.** The fuel-mix differs greatly across the country, and each area will face different dynamics. States decisions on rule implementation could greatly influence cumulative impacts.
- **Outage coordination.** Given the tight window for compliance, many affected units may need to take maintenance outages concurrently, which can exacerbate resource adequacy concerns and reduce needed flexibility.
- **Transmission and operational issues.** The retirement of larger and/or strategically situated generating units will cause changes to the power flows and stability dynamics of the bulk power system. These changing characteristics will require enhancements to the interconnected transmission system to provide reactive and voltages support, address thermal constraints and provide system stability.
- **Uncertainty.** A major concern is the lack of certainty on both the generating supply side and from the Environmental Protection Agency due to rules not being finalized.

Recommendations from the assessment to address these key issues include:

- **Regulators.** Consider time and scope of regulation and affects on bulk power system reliability. Coordination is needed among federal agencies to ensure the industry is not forced to violate one regulation in order to meet another.
- **Industry.** Employ available tools to mitigate potential reliability concerns through any resource transition.
- **NERC.** Continue to assess implications of regulations as greater certainty emerges around industry obligations, technologies, timelines and targets.

Click here to download the *2011 Long-Term Reliability Assessment*.

Cauley, Lauby Participate on FERC Technical Conference Panels

WASHINGTON, DC – The North American Electric Reliability Corporation (NERC) participated in the Federal Energy Regulatory Commission (FERC) two-day, technical conference that began Tuesday. The conference addressed priorities related to the reliability of the bulk power system. NERC **President and Chief Executive Officer Gerry Cauley** testified on Panels 1, 2 and 4. On Wednesday, **Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis,** participated on Panel 3, which discussed emerging issues, including processes used by planning authorities and other entities to identify reliability concerns that may arise in the course of compliance with Environmental Protection Agency regulations, and the tools and processes available to address any identified reliability concerns.

Click here for testimony.

NERC Board Approves Vegetation Management Standard; Focuses on Four Pillars of Success

ATLANTA – The North American Electric Reliability Corporation (NERC) had its quarterly Board of Trustees meeting on November 3 in Atlanta. NERC President and Chief Executive Officer Gerry Cauley welcomed NERC board members; Federal Energy Regulatory Commissioners John Norris and Cheryl LaFleur; and industry stakeholders.

In its fifth year as the electric reliability organization, NERC strives to build upon four pillars for continued success. Those foundations are:

- **Reliability** – addressing real problems to improve the reliability of the grid.
- **Accountability** – being accountable to customers, the industry and government for the performance of the grid.
- **Learning** – enabling the industry to learn from experience to improve future reliability performance.
- **Risk-based model** – focusing actions and programs on issues most important to grid reliability.

"There must be a clear and compelling understanding about what we are trying to accomplish as the electric reliability organization," Cauley said. "By focusing on these four pillars, our role is reliability and our objectives are clear."

During this meeting, the board approved the Project 2007-07 Vegetation Management (FAC-003-2), which is a results-based, foundational standard that provides a defense-in-depth approach to vegetation inspections and minimum clearance distances.

The board also approved the Reliability Standards Development Plan for 2012-2014, which addresses different aspects of standards prioritization; and two Rules of Procedure changes – *Rules of Procedure Non-substantive Capitalization and Definition* changes and *Reinstatement of Section 402.1.3.2*.

Three regional standards – Reactive Power Capability (MOD-025-RFC-1), Mitigation in the ERCOT Interconnection (IRO-006-TRE-1) and Automatic Underfrequency Load Shedding (PRC-006-SERC-1) – received approval as well.

In the Member Representative Committee meeting November 2, the committee elected its officers for 2012: Scott Helyer of Tenaska Corporation as chair and Carol Chinn of American Transmission Company as vice-chair.

NERC's next board meeting is February 9 in Phoenix.

Compliance

NERC Hires New Enforcement Director

WASHINGTON, DC – The North American Electric Reliability Corporation (NERC) announced today that Kenneth Lotterhos will join NERC as associate general counsel and director of compliance enforcement, effective December 5.

Lotterhos comes to NERC from Navigant Consulting Inc., where he was managing director of the Energy Practice's Power Systems, Markets and Pricing group. Prior to joining Navigant, Lotterhos served at Edison Electric Institute as the director of Federal Regulatory Affairs.

Previously, Lotterhos clerked for the Energy Practice group at LeBouef, Lamb, Green and MacRae in Washington, DC, and held various engineering positions in the electric industry, including senior operations engineer for the Northeast Power Coordinating Council and a planning engineer for the Long Island Lighting Company.

"Ken's vast experience in the electric industry will benefit NERC, the industry and stakeholders," said Gerry Cauley, president and chief executive officer at NERC. "NERC has made much progress in the

compliance enforcement program, the addition of Ken ensures we will continue that forward progress."

Lotterhos earned his Bachelor of Science degree in electric engineering from Polytechnic University of New York, and his juris doctorate from George Washington University Law School.

Update on Compliance Application Notices

The redrafting of previously posted Compliance Application Notices is almost completed. In the coming weeks, all CANs will have gone through the CAN process again and will be reposted as final. Some redrafting included changes in the compliance assessment direction for Compliance Enforcement Authorities. NERC appreciates the work of entities in providing comments.

CAN-0027 TOP-003 R2, Coordination of Scheduled Outages, is currently posted for industry comments. The comment period closes on December 15, and this is the last CAN that will be posted in for industry comments this year.

NERC anticipates completing work for several CANs in process that will be posted as final this year. These may include: CANs 0005 and 0007, which were previously post as final. CANS 0024, 0027, 0030 and 0031 will be posted as final for the first time. The topics for these CANs can be found on the NERC website: Complete List of CANs and Status. NERC will send out email announcements as more activity occurs.

With the help of industry, the Standards Committee and the Compliance and Certification Committee, NERC is determining CAN prioritization. NERC encourages industry and interested parties to look at the CAN Status Spreadsheet posted online to view in-queue issues and provide feedback. Additionally, any comments provided on potential CAN issues *prior* to the development process assists in formulating first drafts. Send comments to cancomments@nerc.net and include the name of the CAN and number, if one has been assigned, in the title of your email.

As part of the improved CAN process, a CAN template, Industry Prioritization Form, CAN Comment Form, Standards Suggestion Form, and CAN High-Level Review Request Form have been added to the website for ease of participation in the process.

Workshop News

The next Compliance workshop is December 6 in Atlanta. Agenda topics include an "About NERC" session; JRO/CFR Concurrent Registration; CANs Update; CIP Auditing Issues; a panel discussion on several entities' successful audits; Enforcement Direction; and the 2012 CMEP Implementation Plan. For registration and details, please click here Workshop Registration and Hotel Registration

Critical Infrastructure

NERC Completes First GridEx 2011

WASHINGTON, DC -- NERC's first bi-annual security exercise, GridEx 2011, took place November 16-17, 2011, as part of its ongoing security readiness program. The grid security exercise tested both NERC's and the electricity industry's crisis response plans and validated readiness in response to a cyber incident. The exercise served as an opportunity to enhance collaboration and strengthen industry security processes and capabilities.

More than 75 industry and government partners participated in the first-ever cybersecurity exercise, which allowed participants to respond to scenario events as they would in the case of a real-time incident. Exercise participants included NERC staff, Regional Entities, registered entities, and U.S. and Canadian federal partners.

For more information on the exercise, contact Brian Harrell.

Reliability Assessment and Performance Analysis

Mark Lauby Named IEEE Fellow

ATLANTA – Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis at the North American Electric Reliability Corporation (NERC), was named a Fellow by the Institute of Electrical and Electronics Engineers (IEEE).

The grade of IEEE Fellow is conferred upon a person with an outstanding record of accomplishments in an IEEE field of interest. Lauby received the honor for "leadership in the development and application of techniques for bulk power system reliability." An IEEE Fellow is the highest grade of membership.

"It is no surprise to NERC or the industry that Mark received this esteemed recognition," said Gerry Cauley, president and chief executive officer at NERC. "Mark has been instrumental in developing independent assessments and metrics at NERC that help ensure the overall reliability of the North American grid."

Lauby began his career in the electric industry at the Mid-Continent Area Power Pool in Minnesota in 1979. Before joining NERC in 2007, he held numerous senior positions at the Electric Power Research Institute (EPRI), including director of Power Delivery and Markets and managing director, Asia.

Lauby earned both his Bachelor of Science and Master of Science degrees in electrical engineering from the University of Minnesota. He also attended the London Business School's Accelerated Development Program.

For more information on NERC, please visit www.nerc.com. For more information on IEEE, visit their website at www.ieee.org.

NERC Spare Equipment Database under Development

ATLANTA – The North American Electric Reliability Corporation (NERC), through the Spare Equipment Database Task Force, announced the development of a spare equipment database that allows the industry to track spare long-lead time transformers.

Provision of information in the database, which will begin development in January, will be voluntary. The database will be populated and managed by participating organizations, facilitating timely communication between entities needing long-lead time to replace damaged equipment – which will be extremely helpful in the aftermath of a high impact, low frequency event, such as coordinated attack or extreme weather.

NERC's initial focus will be on high voltage transmission and generator step-up transformers, vital for operation of the integrated bulk electric system. However, the database is not intended to replace current transformer sharing agreements; rather, it provides industry another tool of communication for tracking spare equipment.

"The equipment identified by industry for the spare equipment database concentrates on supporting the needs of the bulk electric system after a significant event that damages large amounts of equipment," said Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis. "Agreement to participate demonstrates industry's continued commitment to reliability and to strengthening the resiliency of the bulk electric system."

For a copy of the Spare Equipment Database System report, click here. The Spare Equipment Database Task Force was formed in response to recommendations in the June 2010 joint NERC, Department of Energy report – *High Impact, Low Frequency Event Risk to the North American Bulk Power System*.

Winter Reliability Outlook Good, Assessment Finds

ATLANTA – The outlook for reliability of the bulk power system this winter appears good, reports the North American Electric Reliability Corporation (NERC) annual *Winter Reliability Assessment* released today.

"Based on projected generation and demand and regional self-assessments, the upcoming winter planning reserve margins appear adequate to maintain bulk power system reliability," said Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis at NERC. "NERC and the Regional Entities have reviewed industry preparations for the upcoming winter season, and highlighted measures taken to address weather trends that may deviate from normal patterns."

NERC posted four cold snap lessons learned from industry outlining best practices for winter preparation and expects to publish more in the coming months. NERC and the Regional Entities continue to monitor industry winterization preparation progress. Key highlights from the *2011/2012 Winter Reliability Assessment* include:

- Reserve margins across North America are forecast to be adequate for 2011/2012 winter season.
- Winter preparations, including winterization of assets in the southwestern United States, are ongoing.
- Industry continues to prepare for the ongoing drought conditions, which are unlikely to abate in Texas, Oklahoma and New Mexico due to La Niña weather patterns.
- Fossil-based fuel supplies and production appear to be adequate for the upcoming winter season.

Click here to download the complete assessment. Visit the Reliability Assessments site for other NERC reports.

Standards

Project 2010-17: Bulk Electric System Definition Update

On November 18, the Federal Energy Regulatory Commission (FERC) issued Order 743 (subsequently clarified in Order 743-A) and directed NERC to revise the definition of Bulk Electric System (BES) for the definition to encompass all elements and facilities necessary for the reliable operation and planning of the interconnected bulk power system. The Commission established a filing deadline of January 25, 2012, for all portions of the project.

NERC is working to address these directives with two activities. The definition of BES was revised through the standard development process, and a BES definition exception process is under development as a proposed modification to the Rules of Procedure. The proposed definition of BES, the implementation plan, and the draft application form, titled "Detailed Information to Support an Exception Request," were approved by industry ballot on November 21, and will be filed with FERC by January 25, 2012.

The associated draft Rules of Procedure Exception Process, which addresses the process for requesting BES exceptions, was vetted by the industry according to the NERC bylaws and will be included as a new Appendix 5C and other related rules changes.

During the initial posting of the draft BES definition for industry comment, the Project 2010-17 SDT received many suggestions that fall outside the narrow scope of the regulatory directives. Upon consideration of policy input and direction received from the Member Representatives Committee and the NERC Board of Trustees, the Project 2010-17 SDT determined that developing an adequate technical justification for these additional revisions to the BES definition was highly unlikely in the time frame established by Order No. 743. Thus, the standard development team developed a plan for subdividing Project 2010-17 Definition of BES into multiple phases to meet the original FERC deadline while giving serious consideration to issues raised by stakeholders.

The first phase of this project addressed the directives established by FERC in Order Nos. 743 and 743-A. The second phase of this project will address concerns raised by drafting team members and concerns received from stakeholders through the standard development process. Commenters have been informed that the issues identified above will be fully addressed in the next phase of Project 2010-17 Definition of Bulk Electric System.

The Standards Committee approved the multi-phased approach and is committed to keeping this project on its "high priority" project list. The same drafting team will continue development work, without pause, through completion of Phase II.

A supplemental SAR for the second phase of the project was posted for information during the balloting for the first phase. Now that the first phase has been successfully completed, the Project 2010-17 drafting team will focus on the second phase.

Addressing FERC Order 754

Following a technical conference concerning the Federal Energy Regulatory Commission's Order 754 (Single Point of Failure), which took place October 24-25 in Washington, DC, industry experts and NERC staff have continued to work to address the Commission's concern with the study of single point of failure on protection systems.

As a result of the meeting, two informal groups formed to prepare materials according to the identified problem statement: "The group perceives a reliability concern regarding the comprehensive assessment of potential protection system failures by registered entities. The group agrees on the need to study if a gap exists regarding the study and resolution of a single point of failure on protection systems." These materials will be filed with FERC for information in early 2012.

Both informal groups will present information to the members of the NERC System Protection and Control Subcommittee and Transmission Issues Subcommittee at their December 2011 joint meeting. Presentations will focus on two approaches for responding to the Commission's concern; the goal of the meeting will be to reach consensus on whether to move forward with a data request in accordance with the NERC Rules of Procedure, Section 1600 or an interpretation request for reliability standards TLP-003-0a and TPL-004-0.

NERC staff plans to post materials for stakeholder review prior to the joint meeting. Additional information is available on the Order 754 project page on NERC's website. For inclusion on email notices regarding Order 754 and information about the upcoming joint meeting, contact Scott Barfield-McGinnis.



Peter Heidrich, of FRCC, presents Project 2010-17 Definition of BES during the two-day workshop

Fall 2011 NERC Reliability Standards and Compliance Workshop a Success

NERC hosted its second Reliability Standards and Compliance Workshop of 2011 October 26-28 at the JW Marriott in Atlanta. Approximately 150 industry stakeholders joined NERC staff, with an additional 150 participating via webinar.

The workshop focused on the interrelationship between standards and compliance, and included a NERC Standards 101 presentation along with sessions on feedback loops among the standards and

compliance departments; standards activities and plans for the future; the Bulk Electric System definition project; critical infrastructure protection issues; CANs, interpretations, and other standards improvement processes; and more. Both NERC President and CEO Gerry Cauley and FERC Commissioner Cheryl LaFleur offered keynote presentations during the event.

Workshop slides and other resources are available on NERC's Standards Workshops web page. Dates for NERC's 2012 March and October workshops will be announced soon.

NERC Introduces Weekly Standards Bulletin

NERC issued its first weekly standards bulletin on November 7, which will now be circulated to stakeholders each Monday morning. The weekly bulletin compiles a list of current and upcoming standards, interpretations and CANs posted for comment, industry review or ballot, along with a list of upcoming standards-related postings and events.

Feedback on the bulletin's effectiveness, content and format is welcomed and should be sent to Mallory Huggins. If you would like to subscribe to the distribution list that includes the bulletin, send an email to subscribe-standards@listserv.nerc.com.

NERC Standards 101 Presentation Now Available

A streaming webinar of the NERC Standards 101 presentation has been posted to NERC's webinar page, along with the webinar slides. The presentation includes a brief overview of NERC and then a more in-depth look at NERC's standards processes. The information should be useful for anyone new to NERC or the standards arena, or anyone looking for a refresher on the basics of NERC's standards processes.

Because NERC's standards processes and tools are always evolving, this presentation will be updated in 2012 to reflect new initiatives and updates to the website.

Note that this presentation was recorded before certain standards website upgrades, so the website portion of the presentation has been removed to reduce confusion.

Additionally, NERC updated its document templates after the presentation was recorded. The stand-alone slides posted reflect the newest template for printing purposes, but the streaming presentation uses NERC's previous template.

Please send comments or suggestions for future improvement to Mallory Huggins.

Standard Drafting Team Vacancies

Any industry stakeholder meeting the indicated qualifications for one of the following three vacant appointments may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

Project 2007-06 System Protection Coordination

Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

Project 2007-12 Frequency Response

Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

Project 2010-07 Generator Requirements at the Transmission Interface

Seeking an individual who is currently a NERC-certified System Operator, preferably as a Transmission Operator or Reliability Coordinator. The candidate should also be familiar with the history of the GOTO Ad Hoc Group, recent registration activity, and the work of the Project 2010-07 SDT.

Please contact Andy Rodriquez with questions regarding the vacancies.

Filings

NERC Filings to FERC

(click on the link for full filing)

November 7, 2011

Compliance Filing in Response to the October 7, 2011 Order

NERC submits a Compliance Filing in Response to the October 7, 2011 Order. Specifically, in the October 7, 2011 Order, the Commission rejected NERC's proposal to delete Section 402.1.3.2 of the NERC Rules of Procedure; this compliance filing is made to restore Section 402.1.3.2 to the NERC Rules of Procedure. *Docket No. RR10-11-000* **Supplemental Information Regarding CIP Version 4 VRFs and VSLs**

November 10, 2011

Joint Motion for Extension of Time to Submit Compliance Filing

NERC, WECC, et al. submit a joint motion for extension of time from November 14, 2011 to December 2, 2011 to allow NERC to submit a compliance filing in response to the Commission's June 16, 2011 Order regarding the registration of Cedar Creek Wind Energy, LLC and Milford Wind Corridor Phase I, LLC. The Commission directed NERC to submit a compliance filing identifying the Reliability Standards and Requirements that will be applicable to Cedar Creek and Milford. *Docket Nos. RC11-1-000 and RC11-2-000*

November 14, 2011

Motion for Leave to Answer and Answer

NERC submits a Motion for Leave to Answer and Answer in response to the Petition Requesting Approval of New Enforcement Mechanisms and Submittal of Initial Informational Filing Regarding NERC's Efforts to Refocus Implementation of its Compliance Monitoring and Enforcement Program. NERC's Answer is limited and will clarify certain concerns raised in the comments of the ISO/RTO Council (IRC). *Docket No. RC11-6-000*

Petition for Approval of a Revision to the Rules of Procedure-Correction to Section 1.3 of Appendix 4D

NERC submits a Petition for Approval of a Revision to the Rules of Procedure of the North American Electric Reliability Corporation – Correction to Section 1.3 of Appendix 4D, "Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards." D*ocket No. RR11-_-000*

November 21, 2011

Comments in Response to NOPR on Reliability Standard PRC-023-2

NERC submits comments in response to the Notice of Proposed Rulemaking on proposed Reliability Standard PRC-023-2 - Transmission Relay Loadability. *Docket No. RM11-16-000*

Comments in Response to NOPR on Version 4 CIP Reliability Standards

NERC submits comments in response to the Notice of Proposed Rulemaking on the Version 4 Critical Infrastructure Protection Reliability Standards. *Docket No. RM11-11-000*

November 22, 2011

Motion for Extension of Time regarding System Personnel Training Reliability Standard

NERC submits a Motion for Extension of Time to address the directive in Order No. 742 regarding whether personnel that support EMS applications should be included in a Support Personnel Training Reliability Standard, in accordance with NERC's Reliability Standards Development Plan 2012-2014. *Docket No. RM09-25-000*

Motion for an Extension of Time regarding a new Generator Relay Loadability Reliability Standard

NERC submits a Motion for Extension of Time to address the directive in Order No. 733 to develop a new generator relay loadability standard, in accordance with NERC's Reliability Standards Development Plan 2012-2014. *Docket No. RM08-13-001*

Petition of NERC for Approval of Amendments to Delegation Agreement with WECC - Amendments to WECC's Bylaws and Regional Reliability Standards Development Procedure

NERC submits a petition requesting the Commission's approval of amendments to the Amended and Restated Delegation Agreement between NERC and the Western Electricity Coordinating Council ("WECC"), one of the NERC Regional Entities (the "WECC RDA"). The proposed amendments to the WECC RDA consist of amendments to Exhibit B – the WECC Bylaws, and to Exhibit C – the WECC Regional Reliability Standards Development Procedure ("RSDP"). *Docket No. RR12-__-000*

November 23, 2011

Third Quarter 2011 Compliance Filing of the North American Electric Reliability Corporation in Response to Paragraph 629 of Order No. 693

NERC submits the Third Quarter 2011 Compliance Filing of the North American Electric Reliability Corporation in Response to Paragraph 629 of Order No. 693. Order No. 693 requires that NERC provide a quarterly informational filing regarding the timeframe to restore power to the auxiliary power systems of U.S. nuclear power plants following a blackout as determined during simulations and drills of system restoration plans. This filing contains the referenced material pertaining to the third quarter of 2011. *Docket No. RM06-16-000*

November 29, 2011

Petition for Approval of Definition and Capitalization Revisions to the NERC Rules of Procedure

NERC submits a petition for approval of Definition and Capitalization Revisions to the NERC Rules of Procedure. The purposes of the proposed revisions are (1) to place all definitions

of defined terms used anywhere in the ROP in a single, readily-accessible location (proposed new Appendix 2); (2) to capitalize defined terms throughout the ROP where such terms are intended to be used in their defined meanings; and (3) to lower-case other terms that are currently capitalized in the ROP but are not defined terms. *Docket No. RR012-__-000*

NERC Filings in Canada, click here
(click on the link above for full filing)

November 30, 2011
Third Quarter 2011 Application for Approval of Reliability Standards (Nova Scotia)

Careers at NERC

Manager of Reliability Risk Management
Location: Atlanta
Details

Bulk Power System Awareness Analyst
Location: Atlanta
Details

Compliance Enforcement Administrative Assistant
Location: Washington, DC
Details

Manager of Notice of Penalty (NOP) Development
Location: Washington, DC
Details

Senior Compliance Enforcement Engineering Analyst
Location: Washington, DC
Details

Data Management System Specialist
Location: Washington, DC
Details

Manager of Compliance Analysis, Reporting, and Tracking
Location: Washington, DC
Details

Compliance Auditor
Location: Atlanta
Details

Administrative Assistant to Critical Infrastructure Department
Location: Washington, DC
Details

Event Investigator
Location: Atlanta
Details

Attorney
Location: Washington, DC
Details

Attorney
Location: Washington, DC
Details

Business Analyst
Location: Atlanta
Details

Manager of Power System Analysis
Location: Atlanta
Details

Executive Assistant to Standards Department
Location: Atlanta
Details

Standards Development Adviser
Location: Atlanta
Details

Reliability Standards Analyst
Location: Atlanta
Details

Reliability Standards Adviser
Location: Atlanta
Details

Standards Specialist
Location: Atlanta
Details

Other News

Canadian Electricity Association's Pierre Guimond discusses impact of U.S. environmental regulations on Canada's grid

E&E TV – December 1

What are the opportunities for grid infrastructure investment between the United States and Canada? During today's OnPoint, Pierre Guimond, president and CEO of the Canadian Electricity Association, explains how the United States' transmission and environmental regulations will affect the Canadian electricity industry. He also weighs in on the clean energy standard discussion in light of Senate Energy and Natural Resources Committee Chairman Jeff Bingaman's (D-N.M.) push to introduce legislation next year.

Transcript

Monica Trauzzi: Pierre, as the U.S. and Canada move forward on several strategic relationships relating to energy, your group's perspective on power is an interesting one. What are the opportunities you see for infrastructure investment between the United States and Canada?

Pierre Guimond: The North American grid, both the American and Canadian grids are interconnected. They operate almost as a single unit and so what we have on our side of the border is -- looks a lot like what you have on your side of the border, the same sort of assets, the same sort of equipment. Our side is predominantly non-emitting electricity in that we have 60 percent hydroelectricity, another good 15 percent nuclear and then add wind and solar and the others to that and we're looking like about 80 percent non-emitting. Whereas on the U.S. side, you use a lot more coal than we do. So, we have different strengths and positions in terms of assets and the ability to generate. In terms of transmission, we're interconnected. We move a lot electricity from faraway sites to where the customer lives and we've always been interconnected with the U.S. At first it was just to stabilize the systems, but in recent decades it's turned into a real commerce of electricity proposition.

Monica Trauzzi: So, when FERC releases a major rule like Order 1000 as it did earlier this year, you look at it. Do you see that there's a consideration of Canada and the relationship on transmission that the United States has with Canada?

Pierre Guimond: Well, that's the magic ingredient that needs to be there. We look at FERC orders and we're compliant with a lot of FERC orders in that we agree that they are needed in order to have a fully functioning marketplace for electricity. We comply with FERC orders by, on our side of the border, having the provinces which have jurisdiction over electricity in Canada, basically adopt similar regulations and similar standards. The way we do that is very much a function of how we govern ourselves. So, we are always mindful when we see a FERC order come around as to what is it trying to achieve? Do we agree with that and what's the best way of dealing with it? Oftentimes we have to consider the possibility that FERC may be going a little bit too far and that happens, but it happens in a very gentle way so far and so we're able to deal with it. Our provinces are pretty understanding and pretty flexible when it comes to certain things.

Monica Trauzzi: So, on Order 1000 specifically, what's your view? There's been a lot of criticism here in the U.S. that FERC didn't quite handle the cost allocation fairly. What's your view?

Pierre Guimond: We're trying to figure out. Like many U.S. utilities, our utilities that are involved in the commerce of electricity, are looking at the order and trying to determine just how far it goes and how far it needs to go. We, as a sovereign country, don't like to have someone else's government too far into our own affairs and so that's a judgment call on our part. We'll have to figure that out. FERC is always best able to serve North America when the Canadians agree to be served.

Monica Trauzzi: When you think about transmission differences between the United States and Canada, it sounds like the Canadians are using a lot more renewable energy at this point. What do you see as the key differences and challenges?

Pierre Guimond: As we go forward, North America, both the Canadian and the U.S. sides are going to be facing three basic challenges. One, our system is aging. Our equipment was built by our father's and grandfather's generations and we have to invest a lot in refurbishing some of the basic equipment that we have. Secondly, we're changing technologies. We're moving from the old analog equipment to more digital and that's where the smart grid idea comes in and that is a pretty big change in the way we make, move, and sell electricity. And the third one is the one that we like to talk about so much in the media and that is dealing with greenhouse gas emissions. That will bring a new set of choices to the electricity sector in both countries and we'll have to figure out how we're going to produce all of that electricity that so many of our customers love to enjoy and to use and are using in more and more varied ways every day, so that we can produce that electricity so that it's affordable, reliable and also competitively priced. So, those are the big challenges as we go forward. You know, the three sisters as we like to call them.

Monica Trauzzi: Do you think it's possible to implement strong air regulations and not compromise power sector reliability?

Pierre Guimond: I think reliability is the number one importance to everyone that is in the business and in order to maintain and ensure increased reliability as we go forward, we have to really talk to each other. We have to make sure that we understand what we're proposing by ways of rules of the road, regulations, and even legislation. I think electricity on our side of the border is less intense in terms of air emissions than the electricity produced on the U.S. side. Over time, I suspect that the two systems will be more consistent, that we'll look like each other a lot more. So, I think we continue to need fossil fuels and we will continue to need fossil fuels for many decades to come. We have to figure out how to keep the environment clear, clean and also use those fossil fuels. That's another big challenge.

Monica Trauzzi: You mentioned smart grid, cyber security is a big issue that we're talking about here in the United States that relates directly to the smart grid. What kind of solutions, cooperative solutions do you see in handling the cyber security issue?

Pierre Guimond: On our side of the border we're pretty well organized in terms of cyber security in that we have a very robust system for talking to each other and sharing information. We've come to a clear understanding of what kind of information that we need to share and how we should share it. In many ways, that is a very useful lesson. We can help the U.S. on that because we've developed a workable model. Tomorrow, for example, back in Ottawa I'll be spending a day with our public safety officials of the federal government where they're going to be sharing information with the energy sector. And it's a full day being locked up and sharing information, as much as we can, so as to improve the overall objective that we share.

Monica Trauzzi: One final question here. Senator Bingaman has signaled that he would like to move forward with a clean energy standard early next year. How would Canada benefit if a CES were to be implemented here in the United States?

Pierre Guimond: The CES should, in our view, have due regard for the fact that we have a lot of non-emitting, affordable and reliable electricity that is available to Canadians and also available to the United States. There are many times during the day when U.S. homes are lit and heated with Canadian electricity and sometimes during the day and night Canadian industrial plants are powered by U.S. electricity. It's a robust commerce that goes back and forth. I think any CES should really take that into consideration and to take advantage of all that Canadian electricity can offer U.S. customers.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC News

December 2011

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NERC Moves DC Office

Compliance

2012 Compliance Audit Schedule Posted

Make Plans to Attend ERO Auditor and Industry Workshops

Update on Compliance Application Notices

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GridEx Report Being Finalized

Reliability Assessment and Performance Analysis

NERC Assessment IDs Key Findings for Future Industry Dependency on Natural Gas

Standards

Standards Committee Election Update

NERC Responds to FERC Notice of Proposed Rulemaking (NOPR) RM11-18

Addressing FERC Order 754: Data Request Posted for Comment

Project 2010-17: Bulk Electric System Definition Update – Phase 2

Standard Drafting Team Vacancies

Training and Certification

Personnel Certification Governance Committee Membership Nominations

NERC Filings

Documents Filed with FERC and/or Canada During the Month

Careers

NERC Seeks Talented Professionals

Headlines

NERC Moves DC Office

On December 19, the North American Electric Reliability Corporation (NERC) relocated its Washington DC offices to a new location.

The new office address is **1325 G Street NW, Suite 600, Washington, DC 20005**. The main switchboard number is **202-400-3000.** All DC office phone numbers have changed, but emails and cell phone numbers will remain the same. To reach NERC DC employees, contact the main switchboard, send email or use employee cell phone numbers.

The DC move was part of NERC's office relocation strategy, which began in 2010, and included moving NERC headquarters to Atlanta. The relocations were made with long-term goals in mind – including better personnel recruitment and retention; easier access by industry for meetings and conferences; and to strengthen key relationships with industry and government partners. The move to Atlanta was completed in June.

Compliance

2012 Compliance Audit Schedule Posted

A new Compliance Audit Schedule for 2012 was posted to the NERC website December 20. Each Regional Entity develops and updates their individual audit schedules and provides them to NERC on a quarterly basis, at a minimum.

Once NERC receives the individual audit schedules, they are compiled into one common audit schedule and posted. If a Registered Entity has any questions or concerns about the audit schedule, contact the appropriate Regional Entity. Click here for the 2012 Compliance Audit Schedule.

Also posted on December 20 was the revised 2012 ERO CMEP Implementation Plan. The revisions were minor and included the addition of clarifying language regarding the scheduling and reporting requirements for audits of entities registered for the PSE function (pp. 18 and 25). Click here to view the 2012 ERO CMEP Implementation Plan.

Make Plans to Attend ERO Auditor and Industry Workshops

NERC's Audit Assurance and Oversight (AAO) group will conduct two workshops in Salt Lake City, Utah, in February. The three day event is hosted by the Western Electricity Coordinating Council (WECC) and is expected to draw representatives from each of the eight Regional Entities, as well as FERC.

The first of the two workshops, "Planning a Successful Audit," will take place from February 21 through the morning of February 23 and is open to all ERO auditors. Auditing subject matter experts will be featured speakers and interactive breakout sessions will be conducted with attendees.

The second workshop is planned for the afternoon of February 23 and is open to Industry. This public event will focus on industry specific techniques and tools being employed during audits throughout North America. For more details, contact Bill Graham, Compliance Auditor, at 404-446-9656; or Jim Hughes, manager of Audit Assurance and Oversight, at 404-446-2574.

Update on Compliance Application Notices

NERC posted CAN-0040 and CAN-0043 December 30, which brought the total number of CANs posted as final to 25. As the number of CANs increases, it is important that industry and other interested parties are able to locate any CAN relevant to their needs. Currently there are several ways to locate a CAN:

- The first is to go to the NERC Compliance Application Notices page and open the gray bar titled "Compliance Application Notices – Final." This provides a list of final CANs organized by number.
- A second method is to open the gray bar titled "Priority List of CANs" on the same web page. This provides a spreadsheet containing all CANs, from potential topics to final CANS,

which can be downloaded. Once downloaded, the spreadsheet can be filtered and sorted to locate a CAN based on a topic, a standard or other criteria.

- The third method is to open the Reliability Standards web page. Every standard that has an associated CAN have a link to that CAN. This is a quick and easy method of locating a CAN that is specific to a standard, but it will not provide links to broad CANs that cover multiple standards. However, a quick sort of the downloaded spreadsheet for the word "multiple" will provide a list of CANs that apply to multiple standards.

The "Priority List of CANs" spreadsheet also is posted to create an opportunity for anyone who is interested to comment on the importance and the substance of potential CAN issues before it is drafted. A form for providing comments is available under the "Compliance Application Notices Processes and Tools" gray bar on the Compliance Application Notices web page – see CAN Process Appendix 2 – Industry Prioritization Form. These forms may be submitted to the cancomments@nerc.net email address.

Compliance Workshop News

NERC Compliance wants to thank participants of the December 6 Compliance workshop. Slides are posted on the NERC website by following the hyperlink: Workshop Slides. If you attended, please remember to complete the online Electronic Survey. Workshops are intended to provide stakeholders with pertinent information, so include your thoughts on you would like discussed at the 2012 compliance workshops.

Critical Infrastructure

GridEx Report Being Finalized

An after-action review has been drafted following NERC's first sector-wide grid security exercise, GridEx 2011, which took place September 16-17, 2011.

The exercise was designed to validate the readiness of the electricity sector to respond to a cyber incident, strengthen utilities' crisis response functions, and provide input for internal security program improvements. Seventy five industry and government organizations from the United States and Canada participated.

An after action team reviewed player questionnaire submissions, interviews, and exercise communications after the exercise. The findings, which will be highlighted in a final report to industry in late January, identified key themes and recommendations. Some of the findings include:

- Entities possess effective cyber incident response plans, but updates to protocols and guidelines could enhance preparedness.
- Significant horizontal communication occurs across industry, but vertical information sharing to NERC and government agencies is limited due to unclear reporting requirements and concerns about compliance implications. Clearer reporting guidance could promote more information sharing.
- NERC's ES-ISAC and Reliability Risk Management team effectively serve a central coordination function, but expediting the NERC alert process, refining call mechanics and activating the ES-ISAC portal can enhance the organization's response role.
- Because physical intrusions into the bulk power system infrastructure can have grave cyber implications, entities should ensure their response protocols address the coordinated threat.
- While the NERC Emergency Standards process would expedite urgent standards development, requirements could interfere with core incident response activities at the entity level.

For more information on GridEx 2011, please contact Brian Harrell.

Reliability Assessment and Performance Analysis

NERC Assessment IDs Key Findings for Future Industry Dependency on Natural Gas

The majority of new generating capacity projected in the next ten years will rely on natural gas as its primary fuel, a recent assessment by the North American Electric Reliability Corporation (NERC) finds. The *2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States* reviews gas and electric interdependencies, assesses existing and future challenges, identifies areas of vulnerability, and provides recommendations for enhancing reliability.

Increased dependence on natural gas for generating capacity can amplify the bulk power system's exposure to interruptions in natural gas supply and delivery. Strategies – such as storage, firm fuel contracting, alternate pipelines, dual-fuel capability, sufficient pipeline capacity to support normal and emergency operations, access to multiple natural gas basins, or additional transmission lines from other areas – all can help mitigate and manage potential risks to reliability.

"Natural gas is becoming an increasingly important part of the North American fuel mix for electric generation," said Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis at NERC. "This report provides the foundation for both the gas and electric industries to work together, ensuring that sufficient infrastructure and operational coordination is in place to maintain bulk power system reliability."

Key issues identified in the assessment include:

- **Key differences exist.** While the electric industry is somewhat functionally bundled, the natural gas industry is structurally unbundled. This difference makes long-term planning and communication important to operating successfully in different regulatory frameworks.
- **Increase coordination and communication needed.** Information sharing is needed for the reliable operation between both industries to ensure reliability of the bulk power system.
- **Storage solutions diminish interdependency issues.** Future natural gas storage facilities must satisfy traditional fuel supply reliability demands, while taking into account day and nights swings in demand
- **Electric loads present unique challenges.** As the use of gas-fired generation increases, pipeline enhancements may be required to support large concentrated, high pressure variable gas loads.
- **Ample gas supply expected.** In terms of supply, almost all future natural gas growth comes from the electric sector. Shale gas will likely make a significant contribution to the U.S. supply portfolio.
- **Pipeline expansion to accommodate the electric sector.** Pipeline infrastructure planning must take into account the long-term growth of gas-fired generation, as more pipeline capacity ultimately will be needed.

To download the *2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States* assessment, click here.

Standards

Standards Committee Election Update

On November 17, 2011, FERC approved revisions to Rules of Procedure Appendix 3B – Procedure for Election of Members of the Standards Committee.

One of the primary reasons for modifying the Standards Committee election procedure was to change the responsibilities of chair and vice chair so that the officers represent the industry as a whole rather than any one Industry Segment. Under the new procedure, the incumbent Standards Committee

members elect a chair and vice chair to serve a two-year term 90 calendar days before the end of each odd numbered year.

For 2012 and 2013, the incumbent Standards Committee members have elected Allen Mosher of American Public Power Association (Industry Segment 4 – Transmission Dependent Utilities) to serve as chair and elected Ben Li, representing the Independent Electric System Operator (Industry Segment 2 – ISOs and RTOs), to serve as vice chair. Mosher and Li were both elected by the members of their Industry Segments to serve two-year terms. A nomination period to identify candidates to fill the two-year terms left vacant through the election of Standards Committee officers is open through today (January 4).

Individuals interested in representing Segment 2 or Segment 4 on the Standards Committee must submit a nomination form to Monica Benson today (January 4). An election will be conducted immediately after the nominations period closes.

The full Standards Committee roster, listing all 2012 members and their contact information, is available on NERC's website.

NERC Responds to FERC Notice of Proposed Rulemaking (NOPR) RM11-18

NERC filed comments on December 23, 2011, in opposition to FERC's recent Notice of Proposed Rulemaking to remand NERC's revisions to Table 1 footnote "b" of reliability standard TPL-002-0a - System Performance Following Loss of a Single Bulk Electric System Element (Category B). In NERC's response to FERC, it was suggested that a prescriptive approach to forbid loss of load in planning studies and assessments would risk confusion and create potential conflict between FERC and other existing federal and state authorities.

NERC expressed continuing support for the work product filed March 31, 2011, related to footnote "b." The modified standards submitted to FERC in that March filing were developed in response to a directive in FERC's 2007 Order No. 693, ordering NERC to clarify standards regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. While FERC asserted in Order No. 693 that such actions were impermissible, NERC and its stakeholders felt such interruptions should be allowed, provided they are reviewed through an open and transparent stakeholder process that includes addressing stakeholder comments. Similar language is incorporated in the proposed rewrite of the entire family of TPL standards as TPL-001-2 - Transmission System Planning Performance Requirements, which was recently filed with FERC.

Other entities submitted comments supporting NERC's position, stating that FERC should not remand the standard. The National Association of Regulatory Utility Commissioners, American Public Power Association, and Edison Electric Institute, among others, filed comments stating that FERC risks infringing on state jurisdiction and confusion with its own existing jurisdiction under Orders 890 and 1000.

EEI urged FERC to accept NERC's proposed revisions to footnote "b" as filed for approval, saying it outlines an effective process in addressing reliability issues in proportion to the reliability risk. Rather than remanding, EEI recommended that FERC closely monitor the stakeholder processes and require NERC to report on the use of the loss of load provision in footnote "b" when making transmission planning decisions.

For more information, please see NERC's filing.

Addressing FERC Order 754: Data Request Posted for Comment

NERC posted a Request for Data or Information concerning the Federal Energy Regulatory Commission's Order 754 (i.e. the study of single point of failure on protection systems) for a 45-day industry stakeholder comment period ending at 8 p.m. Eastern February 6. This data request centers on the Transmission Planner as the reporting entity and requires the assistance of Generation Owners and Transmission Owners. In accordance with the NERC

Rules of Procedure, Section 1600 — Request for Data or Information, NERC may request data or information that is deemed necessary to meet its obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the FERC's regulations. The data request is a component of the information to be filed with FERC in response to the directive in the Order.

Two informational webinars will be conducted on January 5 (register here) and January 20 (register here) to provide stakeholders an opportunity to ask questions regarding the content of the data request. Stakeholders are encouraged to review the information available on the Order 754 project page and submit comments via the electronic comment form during the comment period. For inclusion on email notices regarding Order 754, contact Scott Barfield-McGinnis.

Project 2010-17: Bulk Electric System Definition Update – Phase 2

In the initial phase of Project 2010-17, the standard drafting team and industry comments identified several items in the proposed definition of Bulk Electric System that would require detailed technical justification in order to change from the status quo. The standard drafting team could not address these items in the initial phase, however, because the scope of the original Standard Authorization Request for the project was limited to addressing directives identified in FERC Orders 743 and 743-A. The project was on a tight deadline for responding to these directives. Therefore, the standard drafting team decided to delay addressing these additional items until Phase 2 of the project.

Phase 1 will reach a milestone when the proposed definition is filed with FERC in late January, and Phase 2 will begin shortly thereafter, with posting of the Phase 2 Standard Authorization Request scheduled for today (January 4). The standard drafting team is soliciting industry comments on clarification concerns with the definition, as well as comments on the possible direction of the technical justification for changing from the status quo on a number of items (for instance, generation thresholds). Industry comments are due on February 3.

Standard Drafting Team Vacancies

Any industry stakeholder meeting the indicated qualifications for one of the following three vacant appointments may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

Project 2007-06 System Protection Coordination
Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

Project 2007-12 Frequency Response
Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

Project 2010-07 Generator Requirements at the Transmission Interface
Seeking an individual who is currently a NERC-certified System Operator, preferably as a Transmission Operator or Reliability Coordinator. The candidate should also be familiar with the history of the GOTO Ad Hoc Group, recent registration activity, and the work of the Project 2010-07 SDT.

Please contact Andy Rodriquez with questions regarding the vacancies.

Training and Certification

Personnel Certification Governance Committee Membership Nominations

The NERC System Operator Certification Program is holding open nominations to fill one opening on the Personnel Certification Governance Committee. The term of service will be from March 1 through December 31, 2014. Nominations will be accepted until February 3.

The PCGC Nominating Subcommittee will consider nominees with the following qualifications:

- Must have a valid NERC system operator credential.
- Must have experience in interconnected system operations

A brief description of responsibilities: Protect the Integrity of the System Operator Certification process, attend and participate in four in person PCGC meetings, participate in various conference calls and subcommittee tasks.

To download nomination documents, click on hyperlinks: PCGC Charter, PCGC Nomination Letter, and PCGC Nomination Form.

For more information, contact Nancy DeLeon via email or call 404-446-9730.

Filings

NERC Filings to FERC

(click on the link for full filing)

December 2, 2011

Compliance Filing in accordance with the June 16, 2011 Order

NERC submits a filing in compliance with the directives in the Commission's Order issued June 16, 2011. The June 16 Order upheld the registration of Cedar Creek Wind Energy and Milford Wind Corridor Phase I and required them to comply with a list of Transmission Owner and Transmission Operator Reliability Standards and Requirements that apply to the entities. *Docket Nos. RC11-1-000 and RC11-2-000*

Response to Request for Production and Request for Confidential Treatment

NERC submits a Response to Request for Production and Request for Confidential Treatment in response to the request of City of Holland. *Docket No. RC11-5-000*

December 5, 2011

Reply Comments in response to Notice of Proposed Rulemaking on CIP Version 4 Reliability Standards

NERC submits reply comments in response to comments filed in response to the Notice of Proposed Rulemaking on CIP Version 4 Reliability Standards. *Docket No. RM11-11-000*

December 13, 2011

NERC Standards Development Plan 2012-2014 Informational Filing Pursuant to Section 310 of the NERC Rules of Procedure

NERC submits the Standards Development Plan 2012-2014 Informational Filing Pursuant to Section 310 of the NERC Rules of Procedure detailing current and upcoming Standards projects and timelines. *Docket Nos. RM05-17-000, RM05-25-000, RM06-16-000*

December 21, 2011

Comments of NERC in Response to NOPR on Transmission Planning Reliability Standards Table 1, Footnote 'b'

NERC files Comments in Response to Notice of Proposed Rulemaking regarding a proposed revision to footnote 'b' of Table 1 in four proposed Transmission Planning Reliability Standards. *Docket No. RM11-18-000* **NERC**

Petition for Approval of Proposed Reliability Standard FAC-003-2 - Transmission Vegetation Management

NERC files a Petition for Approval of Proposed Reliability Standard FAC-003-2 — Transmission Vegetation Management. *Docket No. RM_-__-___*

December 23, 2011

Comments in Response to Underfrequency Load Shedding NOPR

Comments in Response to Notice of Proposed Rulemaking regarding Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards. *Docket No. RM11-20-000*

Filings in Canada, click here

(click on the link above for full filing)

December 2, 2011

2011 Long-Term Reliability Assessment
2011 Winter Reliability Assessment
2011 Summer Reliability Assessment

December 20, 2011

NERC submits a Notice of Filing of Revisions to the NERC Rules of Procedure. The purposes of the proposed revisions are (1) to place all definitions of defined terms used anywhere in the ROP in a single, readily-accessible location (proposed new Appendix 2); (2) to capitalize defined terms throughout the ROP where such terms are intended to be used in their defined meanings; and (3) to lower-case other terms that are currently capitalized in the ROP but are not defined terms.

Careers at NERC

Manager of Reliability Risk Management
Location: Atlanta
Details

Compliance Enforcement Administrative Assistant
Location: Washington, DC
Details

Manager of Notice of Penalty (NOP) Development
Location: Washington, DC
Details

Senior Compliance Enforcement Engineering Analyst
Location: Washington, DC
Details

Data Management System Specialist
Location: Washington, DC
Details

Manager of Compliance Analysis, Reporting, and Tracking
Location: Washington, DC
Details

Senior Certification and Compliance Auditor
Location: Atlanta
Details

Compliance Auditor
Location: Atlanta
Details

Event Investigator
Location: Atlanta
Details

Helpdesk Analyst Level I, Helpdesk Services
Location: Atlanta
Details

Attorney
Location: Washington, DC
Details

Business Analyst
Location: Atlanta
Details

Manager of Power System Analysis
Location: Atlanta
Details

Technical Training Specialist
Location: Atlanta
Details

Executive Assistant to Standards Department
Location: Atlanta
Details

Standards Development Adviser
Location: Atlanta
Details

Reliability Standards Adviser
Location: Atlanta
Details

Standards Specialist
Location: Atlanta
Details

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC News

January 2012

Compliance

Make Plans to Attend Upcoming ERO CEA Workshop and Industry Seminar

Compliance Application Notice Update

Reliability Risk Management

February Cold Snap Webinar and Update

Save the Date for NERC's first Human Performance Conference in March

Standards

BES Petitions Filed with FERC

NERC Considers Updates to VRF Definitions and Streamlining VSLs

Standard Drafting Team Vacancies

Training and Certification

NERC System Operator Certification Exam Announcement

NERC Filings

Documents Filed with FERC and/or Canada during the Month

Careers

NERC Seeks Talented Professionals

Compliance

Make Plans to Attend Upcoming ERO CEA Workshop and Industry Seminar

The NERC Audit Assurance and Oversight group's semi-annual Electric Reliability Organization (ERO) Compliance Enforcement Authority (CEA) workshop will take place on February 21-23 in Salt Lake City. The theme of the workshop is "Planning a Successful Audit," and is limited to ERO CEA staff. Subject Matter Experts (SME) will be featured speakers and there will be interactive breakout sessions. Click on the agenda for details or visit the Compliance section of the NERC website under Regional Programs.

An industry seminar will take place after the workshop - on the afternoon of February 23 and morning of February 24. The purpose of the seminar is to educate the industry regarding the ERO auditor process; specifically with regard to consistency, reliability and transparency. The seminar is open to the public. Click on the agenda for seminar details. Participants can register via the registration link or through the February calendar of events on the NERC website.

Both the workshop and seminar are being hosted by the Western Electricity Coordinating Council (WECC) and are approaching their maximum attendance capacity. For more information, contact Stacia-Ann Chambers, Bill Graham or Jim Hughes.

Compliance Application Notice Update

NERC has expanded the CAN process to give NERC committees – the Operating Committee, the Planning Committee, the Critical Infrastructure Protection Committee, the Compliance and the Certification Committee and the Standards Committee - and individual registered entities the opportunity to provide recommendations for the order of CAN development and pre-development comments on substantive issues.

Committees were provided a list of 26 CANs in late 2011 for prioritization with an anticipated response by the end of February. Individual entities also may provide input by completing the NERC Process Appendix 2 – Industry Prioritization Form. This form, located on the CANs web page, may be submitted to cancomments@nerc.net.

During this effort, NERC staff will continue work on 11 CANs that were in progress in 2011, but have not yet been posted as final.

CANS Webinar - NERC Compliance will host a webinar February 15 to update auditors and industry on improvements to the CAN process, outline the prioritization procedure and review status. An announcement will be issued within the next week.

Reliability Risk Management

February Cold Snap Webinar and Update

In February 2011, a major cold wave swept across the southwestern United States with extreme low temperatures, wind, ice and snow. Faced with a possible all-time high winter peak electric demand and cold-weather-related issues with generators and fuel supplies, an electric generation capacity shortfall occurred as generators tripped off-line and reserves dwindled.

A webinar took place on January 23 to discuss recommendations of the joint FERC/NERC inquiry report – Outages and Curtailments during the Southwest Cold Weather Event. Earl Shockley, director of Reliability Risk Management, led the discussion with almost 400 NERC members and industry stakeholders participating.

The focus of the discussion was the winter weather preparation and lessons learned from the event analysis. Heather Polzin, lead attorney at FERC, outlined the report's collaborative effort.

For more information, visit the Event Analysis web page

Save the Date for NERC's first Human Performance Conference in March

NERC has initiated a new human performance program to allow a more thorough analysis of events on the bulk power system, and to create a proactive focus on reducing human error and those precursors that impact system reliability. This first NERC-sponsored human performance conference - *Improving Human Performance on the Grid* - will provide a focal point for human performance best practices, bringing sector-specific subject matter experts and stakeholders together into an idea sharing, cooperative forum focused on improving human performance.

The event takes place March 27-29 in Atlanta, and will include workshops on cause analysis and human performance fundamentals, including program designs for individuals and organizations.

The conference includes experts from across industry to promote peer learning; academia, to provide a common vocabulary to accelerate discussion; suppliers/vendors, for networking and assistance; and federal agencies, to increase collaboration and the sharing of reliability knowledge.

More information about the conference and registration information will be available soon on the NERC website.

Standards

BES Petitions Filed with FERC

NERC filed a petition with FERC on January 25 for approval of a revised definition of Bulk Electric System (BES) and revisions to the Rules of Procedure to implement the revised definition. The proposed definition provides a key foundation for NERC's standards program and future standards development and is responsive to the policy input from FERC. The revised Rules of Procedure provide the necessary due process framework to assure trust between the industry and NERC, and ensure that the revised BES definition will be applied in a fair and reasonable manner.

NERC staff thanked Peter Heidrich (FRCC) and Barry Lawson (NRECA) – chair and vice chair respectively, who led the Project 2010-17 Definition of BES drafting team to the completion of Phase 1 within the yearlong timeframe directed by FERC. Thanks also to Carter Edge (SERC), who chaired the parallel Project 2010-07 definition of BES Rules of Procedure drafting team. The hard work of Heidrich, Edge, Lawson, NERC coordinator Ed Dobrowolski and both Project 2010-17 teams demonstrates that reliability goals can be met when the industry works together under strong leadership.

The petition for the approval of the revised definition and the petition for approval of the Rules of Procedure revisions are both available on NERC's Filings web page.

Work on Phase 2 of the BES project, which aims to develop appropriate technical justification to support refinements to the definition that were suggested by stakeholders during Phase 1, is ongoing. A draft Standard Authorization Request is posted for stakeholder comment on the Project 2010-17 web page through Friday (February 3).

NERC Considers Updates to VRF Definitions and Streamlining VSLs

The Standards Committee recently provided more direction to NERC staff to move forward with developing proposals for updating Violation Risk Factor (VRF) definitions and for streamlining Violation Severity Levels (VSLs). A small team made up of NERC staff, industry stakeholders and regional staff responsible for compliance, enforcement and standards have been meeting to examine this opportunity.

The goal of updating VRF definitions is to provide a better basis for the VRF tool, which was introduced last year and received industry support, for use by standard drafting teams. Updating the definitions will provide a consistent methodology for the tool to determine the proper VRF classification of a requirement. Proposed definitions will remain consistent with current regulatory guidance.

The VSL proposal, referred to as "Pro Forma VSLs," aims to create uncomplicated levels of severity that will provide enforcement staff with a straightforward way to classify penalties. VSLs currently have many permutations, making the writing of concise levels difficult. Like VRFs, the pro forma proposal will remain consistent with current regulatory guidance.

Since these projects may affect the NERC Rules of Procedure, the proposed modifications will be posted for industry comment following the Rules of Procedure process. The respective proposals will accompany any such posting to provide the rationale for proposed modifications.

Stakeholders who wish to subscribe to notices about these projects may email Scott Barfield-McGinnis to be added to the general distribution list(s) for VRF definitions, Pro Forma VSLs or both.

Standard Drafting Team Vacancies

Any industry stakeholder meeting the indicated qualifications for one of the following three vacant appointments may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

Project 2007-06 System Protection Coordination
Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

Project 2007-12 Frequency Response
Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.
Please contact Andy Rodriquez with questions regarding the vacancies.

Training and Certification

NERC System Operator Certification Exam Announcement

The NERC System Operator Certification Program has published a new version of each of the NERC System Operator Exams:

Examination Title	Designation	Total Questions	Scored Questions	Cut Score
Reliability Operator Certification Examination	RC	150	125	96
Balancing, Interchange, and Transmission Operator Certification Examination	BT	150	125	94
Transmission Operator Certification Examination	TO	125	100	75
Balancing and Interchange Operator Certification Examination	BI	125	100	75

A blackout period is schedule for February 1-8. New exams will begin on February 9 at all Prometric Centers. The changes include exam questions based on content outline and updated to the current *NERC Reliability Standards* as applicable. Click here for 2012 Exam Resources.

Filings

NERC Filings to FERC

(click on the link for full filing)

January 6, 2012
Informational Filing regarding Paragraph 773 of Order No. 672
On December 23, 2010, NERC submitted an informational filing in response to Paragraph 773 of Order No. 672 regarding the initial Three Year Regional Entity Audits and Plan for Future Audits. NERC submits this informational filing to report that the initial Audit activities of the eight Regional Entities are completed and to provide information on its plans to focus efforts to restructure the Regional Entity Audit Program. *Docket Nos. RR09-7-000 and RR10-11-000*

January 11, 2012
Answer to Comments regarding Compliance Filing for Cedar Creek Wind Energy and Milford Wind Corridor Phase I
On December 23, 2011, the Electric Power Supply Association (EPSA), the Edison Electric Institute (EEI) and the American Wind Energy Association (AWEA) filed comments in the dockets regarding NERC's December 2, 2011 compliance filing for Cedar Creek Wind Energy and Milford Wind Corridor Phase I. NERC submits this answer to the comments. *Docket Nos. RC11-1-000 and RC11-2-000*

January 17, 2012

Compliance Filing in Response to November 17, 2011 Order Approving Reliability Standard FAC-008-3

NERC submits a revision to one VRF for Reliability Standard FAC-008-3, Requirement R2 in compliance with the November 17, 2011 order approving Reliability Standard FAC-008-3. *Docket No. RD11-10-___*

Compliance Filing in Response to November 17, 2011 Order Approving Reliability Standard FAC-013-2

NERC submits a FERC-directed revision to two VRFs and one VSL for Reliability Standard FAC-013-2 in compliance with the November 17, 2011 Order approving Reliability Standard FAC-013-2. *Docket No. RD11-3-___*

January 25, 2012

Petition for Approval of a Revised Definition of "Bulk Electric System" in the NERC Glossary of Terms Used in Reliability Standards

NERC submits a Petition for Approval of a Revised Definition of "Bulk Electric System" in the NERC Glossary of Terms Used in Reliability Standards. *Docket No. RM12-6-000*

Petition for Approval of Revisions to its Rules of Procedure to Adopt a Bulk Electric System Exception Procedure

NERC submits a filing in which it requests the Commission to approve revisions to NERC's Rules of Procedure ("ROP") for the purpose of adopting a procedure for requesting and receiving exceptions from the NERC definition of Bulk Electric System ("BES Exception Procedure"), as directed by the Commission in Order No. 743.2. *Docket No. RR_-__-___*

NERC Filings in Canada, click here

(click on the link above for full filing)

No filings in Canada this month.

Careers at NERC

Senior Compliance Enforcement Engineering Analyst
Location: Washington, DC
Details

Data Management System Specialist
Location: Washington, DC
Details

Manager of Compliance Analysis, Reporting and Tracking
Location: Washington, DC
Details

Engineer of Organization Registration and Certification
Location: Atlanta
Details

Compliance Auditor
Location: Atlanta
Details

Event Investigator
Location: Atlanta
Details

Attorney
Location: Washington, DC
Details

Business Analyst
Location: Atlanta
Details

Engineer Reliability Assessments
Location: Atlanta
Details

Technical Training Specialist
Location: Atlanta
Details

Standards Development Adviser
Location: Atlanta
Details

Reliability Standards Adviser
Location: Atlanta
Details

Standards Specialist
Location: Atlanta
Details

From: Philip A. Fedora
To: grpStaff
Subject: FERC, NYISO grapple with regulating black start service in New York City
Date: Thursday, December 08, 2011 9:29:36 AM

FYI – (highlight mine).

FERC, NYISO grapple with regulating black start service in New York City

December 8, 2011

Printer-Friendly Format

FERC has to decide another case on where its jurisdiction ends and states' begins, this time on generation after TC Ravenswood filed a complaint against the NYISO and the state reliability agency. The New York PSC ordered TC Ravenswood to keep providing "black start service" in New York City after the generator received a FERC order saying it could stop.

Black start service refers to generators that are able to come back after a blackout and help get other generators and thus the grid running again.

The ISO told FERC Tuesday it was trying to keep both orders in effect, keeping the firm as a black start provider that has to fulfill the requirements of the New York State Reliability Council -- independently from the black start requirements in the grid operator's FERC-jurisdictional tariff.

The PSC would have to let TC Ravenswood discontinue the service before the ISO could stop that.

The real aim of the firm's complaint was at the state regulator, said NYISO. The ISO does not have a position on the state versus federal jurisdiction issue but noted that if FERC were to issue a ruling that conflicts with the PSC's, it would potentially be unable to reconcile the two laws.

One area where the ISO cannot reconcile the FERC and PSC orders right now is compensation. NYISO can provide compensation under its tariff but would need a FERC waiver to continue doing so.

The PSC told FERC Tuesday that it was willing to pay TC Ravenswood for the black start service but the generator has not asked it for compensation.

FERC cannot overrule the PSC on this issue since the Federal Power Act reserves authority to states to ensure the adequacy of black start generation facilities and many other powers over generation, said the state regulator.

The federal commission has set up black start service in organized markets, which TC Ravenswood noted is "strictly voluntary," so the PSC cannot order the firm to provide it.

What does the law say?

The Federal Power Act leaves it to the PSC to decide how much black start generation is needed for safe and reliable service but it sets a clear role for FERC when the service involves the transmission and sale of power in interstate commerce, said the state regulator.

The ISO's tariff on black start generation cannot be read to overrule the New York PSC's jurisdiction over generation facilities, reliability, resource adequacy or local distribution facilities.

TC Ravenswood is in Consolidated Edison's territory, known to the wider world as New York City. The utility's local restoration plan results in greater reliability than the ISO's alone would otherwise provide and local generators like TC Ravenswood are key to that.

Local service is faster

The PSC offered an affidavit from one of its staff engineers saying local generators help bring the lights back on faster than waiting for power from upstate.

Consolidated Edison's grid is largely made up of high-pressure, oil-filled cables buried beneath streets which is far different than most utilities. Based on its experiences in the 1965 blackout, the firm started to have its own black start capability at local generators, said the affidavit.

Getting the power back on fast is important in New York City as laws prohibit the occupation of high rise office and apartment buildings without fire systems or lighted escape routes. Blackouts also cut off air conditioning and the city's subway.

EPSA and the IPPs of New York backed TC Ravenswood's arguments that the PSC was overstepping its bounds and stepping on FERC's exclusive wholesale jurisdiction.

Black start service is a voluntary, wholesale service provided by merchant generators under FERC-approved tariffs and is subject to exclusive jurisdiction of the federal commission, said the generator lobbies.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Physical Security

November 18, 2011

RELIABILITY | ACCOUNTABILITY






NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Physical Security

Ralph Anderson, CRISC, RC
NERC

November 18, 2011

RELIABILITY | ACCOUNTABILITY






Agenda

- Review Anti-trust Guidelines, Compliance Intent and Vendor Policy
- Introductions and opening comments
- General trends in compliance – (CIP-006)
- Copper theft trends in the US
- How the UK has approached metal theft and lessons to be learned

Agenda (cont)

- Discuss how an electric utility implemented a program to deter substation break-in's and metal theft
- Panel question and answer session
- Presenter information

Reminders – Dial-in

- Participants are reminded that this conference call is public. The access number was posted on the NERC website and widely distributed. Speakers on the call should keep in mind that the listening audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders

Anti-Trust Prohibited Activities

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs
- Discussions of a participant's marketing strategies
- Discussions regarding how customers and geographical areas are to be divided among competitors
- Discussions concerning the exclusion of competitors from markets
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers

Compliance

- Compliance
  - This presentation is intended to convey observations regarding compliance. It is not intended to establish new requirements under NERC or Regional Reliability Standards or to modify the requirements in any existing NERC or Regional Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time taking into consideration facts and circumstances. Implementation of the observations discussed herein is not a substitute for compliance with the requirements of NERC or Regional Reliability Standards

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Opening Comments

- Opening Comments
  - Brian Harrell
  - Ralph Anderson

- General Trends in Compliance – (CIP-006). Presented by: Matt Stryker - Manager of CIP Compliance Monitoring at SERC

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General Trends in Compliance
Critical Infrastructure Protection (CIP) Standard-006-3

Matt Stryker – SERC Reliability Corporation

November 28, 2011

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CIP-006 CAR

ERO CAR for CIP-006, Dated December 2010

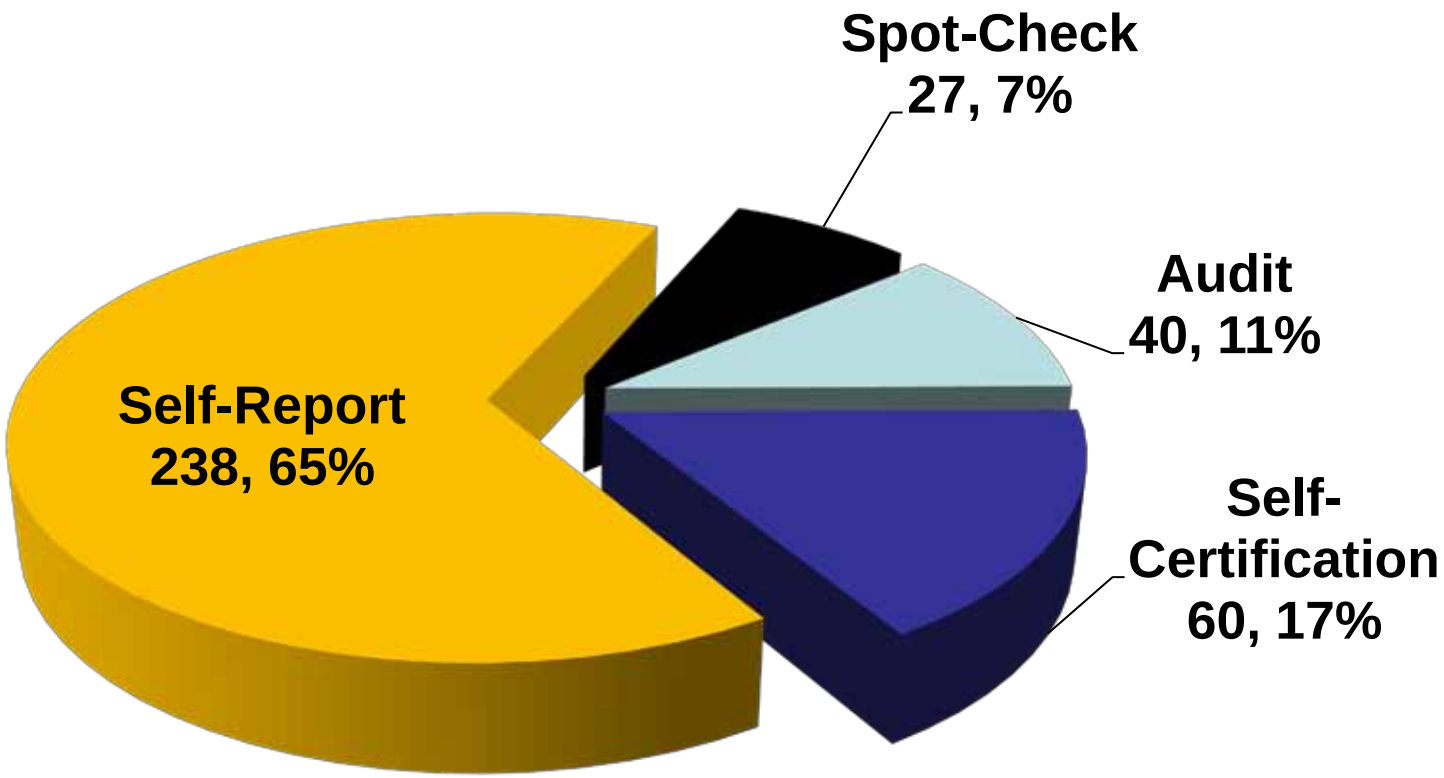
- Analyzed the top 10 violated standards with information and guidance to facilitate compliance.
- Provides a summary of practical information and suggestions based on 103 CIP-006 violations as of September 2010.
- Can be found at www.nerc.com under the Compliance tab.
- CIP-006-3c Compliance Analysis Report

CAR: Violations by Requirement

CIP-006 Violations in Current Version 3 Form	
R1.	164
R2.	34
R3.	10
R4.	51
R5.	44
R6.	32
R7.	12
R8.	18
Totals:	365

Violations By Method of Discovery

CIP-006 Violations by Method of Discovery



CAR Observations

- R1 is the most violated requirement due to its large number of sub-requirements (8).
- Industry deserves credit for their vigilance and the high percentages of self reports.
- Large number of CIP violations is indicative of the newness and the complexity of the CIP standards.

CAR Recommendations

- Entities should have a regular maintenance and testing plan.
- Entities should perform a gap analysis of physical security and access controls at access points to their Physical Security Perimeters (PSPs).
- Entities should verify personnel with unescorted access have necessary access tools (e.g., cards).
- Entities should reinforce concepts of escorted and unescorted access in annual cyber training.

Picture Time

- These pictures do not depict actual PSPs, but are representative photos from non-utility sources.
- Always observe your organization's safety regulations when doing physical inspections.
- Be mindful of electrical, trip, fall, and dust hazards, as well as fire detection and suppression systems.

Raised Floors



Time to get our hands (and clothes) dirty….

Raised Floors



http://en.wikipedia.org/wiki/File:Beneath-the-raised-floor-0a.jpg#filehistory

Dropped Ceilings



Note the wall that rises above the ceiling, but does not extend to the deck above. See CAN-0031 (draft) for guidance on opening sizes.

Dropped Ceilings



A dropped ceiling with tiles removed. Note the numerous openings at the far end of the room.

Data Centers



Mixed use facilities have their own challenges.

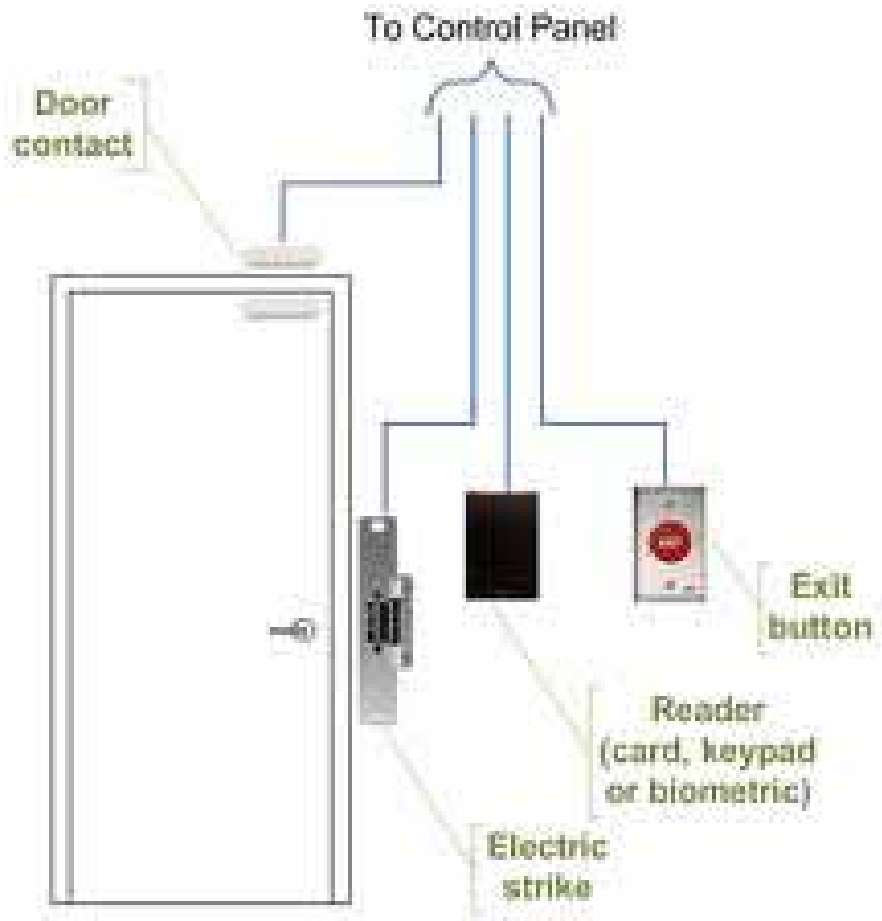
Where's the EACM?



Have you seen this firewall?

CIP-006-3 R3. Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall reside within an identified Physical Security Perimeter.

CIP-006 R4, R5, and R6



For discussion purposes only.

This is not an example of compliance.

CIP-006 R4, R5, and R6



Emergency Situations, or “I wonder what happens to my security when I pull this lever?”

CIP-006 R4, R5, and R6



Other ways through the door...

Summary

- The CAR for CIP-006 identifies a number of common issues seen in the field.
- Inventory management is key to CIP-006-3 R1.1 and R3 compliance.
- Walkdowns help ensure that implementation in the field aligns with the intent of the documented PSP.
- Having an understanding and quality documentation of how your physical access control, monitoring, and logging systems interact will help with audit prep.
- Review upcoming compliance application notices and interpretations which affect Physical Security.

Next Topic

- Copper Theft in the US – Presented by: Ralph Anderson, CIP Training and Exercise Coordinator – NERC

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Copper Theft Trends in the US

Ralph Anderson, CRISC, RC
NERC

November 18, 2011

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Presentation Overview

- History of copper theft
- Who is involved in copper theft
- Impact of copper theft
- Legal considerations
- Guidelines for new facilities
- Guidelines for upgrading existing facilities
- Best practices

History of Copper Theft

- Copper prices have varied greatly over the last 25 years
  - From 1988 until early January 2004, prices were stable at approximately $1/lb with slight variations
    - Most theft was “convenient”, and generally associated with drug abuse
    - Typical chain-link fencing and locked gates deterred most thieves; breaking through fences and locks was not worth the effort required to steal the copper and sell for scrap
    - Warehouse levels of various copper products was adequate, and copper production easily met demand
  - From January 2004 to February 2006 copper consistently increased in price to $2/lb

History of Copper Theft (cont)

- Copper prices fluctuated with the housing market
  - Housing market boom
    - Copper prices were following the housing market, and reached highs over $4/lb.
    - The rate of copper thefts increased due to demand and low warehouse levels, but was not as significant as seen today due to low unemployment rates during housing boom
  - Collapse of the housing market.
    - In July 2008, copper prices were over $4/lb. By December 31, 2008, copper was back to $1.25/lb with record high warehouse levels
    - Copper thefts declined with demand during the collapse of the housing market
- Price fluctuations with the emergence of the Chinese economy
  - Demand for copper in China increased copper prices in the US
    - Prices steadily rose from $1.25/lb in March 2009 to a peak of $4.63/lb in 2011.
    - With US unemployment high and unscrupulous scrap dealers willing to make “deals”, copper theft skyrocketed and became an “illegitimate business”

Who is involved

- Demographics of "typical" thief have change.
  - Drug users used to be the main culprit; that has changed
    - Rise in opportunity
      - Online maps can show aerial views not previously available
        - Search for "targets" from your house via computer
      - This group may not know the hazards. – just that there is copper at a specified location
        - Unaware the dangers involved
      - For those that do not understand the system or design, they may assume a bare conductor cannot be "live" which has resulted in multiple deaths
    - There has been a significant rise in thefts reported to be tied to insider information
      - We have re-evaluate the possibility of insider information
      - Jobless rates are high,; many individuals with specialized knowledge of overall substation and electrical system design are out of work

Impact of Copper Theft – less than 100kV

- Power Outages
  - Typically seen on the electrical distribution system
  - Reported in various news sources:
    - Generally no customers are affected directly due to the copper theft occurring primarily in substations
    - For those that do have reported outages related to copper theft, less than 1,000 customers were reported without power for a short time
    - Reports to date indicate limited copper thefts affected more than 1,000 customers
    - In one case, the same distribution line was replaced multiple times, as a result of thieves who ripped the 4,000 volt distribution line right off the pole for a distance of more than a mile
    - Geographically dispersed – affects every state
    - Many utilities have created special work crews dedicated to copper theft replacement

Impact of Copper Theft on Substations

- Thieves are cutting fences to gain access to substations
  - Target is typically grounding straps ("earthing conductor")
    - These grounding straps are prime targets:
      - Located in remote areas
      - Readily accessible at ground level and easily cut with a bolt cutters
      - They are "bare" copper, require no outer casing removal, just clip and go
    - Substations must ground all structures to ensure electrical safety. (using ground straps). These grounding straps are connected to a large grounding grid under the whole substation
    - Grounding straps are typically two to three feet long, and due to the amount of them in a substation, a thief could quickly get $100 to $200 of "scrap" copper
    - An average ratio is approximately $1 stolen copper results in $10 in repair
    - Induced currents from high voltages could cause death if grounding straps are removed

Impact of Copper Theft on Substations (cont)

- Cutting of control cables for copper
  - Substations use troughs to protect the control cables the operate all the equipment in the substations
  - Control cables provide indication or equipment status, operate protective relays and overall provide the communications within the substation fence
  - If these cables are cut, all indication and control is lost for that specific substation, and may cause mis-operation, or failure to operate as designed which impacts the reliability of the Bulk Power System (BPS)
- In the last 18 months, over a dozen distribution substations have had control cables cut
- In the last 18 months, at least one transmission substation was rendered inoperable due to thieves attempting to steal the copper in the control cables
  - The operators immediately notified polices, and the entire transmission substation had to be taken out of service for repairs
  - Had a system anomaly occurred before the substation was taken out of service, equipment in the substation could have been destroyed

Substation - Illustration



Legal Considerations

- Legal Considerations for Preventing Copper Theft.
  - These vary from state to state to individual cities
    - Due to the large expanse of the BPS and remote locations, law enforcement cannot address all copper theft incidents
    - Budget Issues may impact the ability to enforce the new mandates
    - Preventing copper theft relies on notification which occurs after the fact, long after potential damage is done
    - In remote areas it may be weeks before a substation is visually inspected and damage is noticed
    - In many cases, even with the current legislation in some areas, the judicial system looks at the cost of goods stolen, and often means the difference between if it is treated as a misdemeanor or felony. Often the alleged perpetrator is out on bond in a very short time
    - The US Patriot Act has significant penalties associated with infrastructure damage, but has yet to be used in known cases. Patriot Act, United States Code: Title 18, 1366 – Destruction of an Energy Facility
    - The UK has had success with a specific nationwide task force (will be discussed later in the presentation)

Reducing Copper Theft in New Facilities

- The long term horizon, location, and impact of the new facility on the BPS should be considered during initial design
  - Multiple options exist, and it is recommended to take a long term view
    - Typical chain-link fence can be breached very rapidly with over-the-counter tools
    - Cut-resistant fencing is also subject to battery powered tools that simply slow down the intruder
    - Other fencing should be evaluated on it's own merits, and the potential outlook on the long term planning horizon

Existing Facility Upgrades

- Consider the near-term and long-term horizon, especially the impact of the facility on the BPS. Each facility and impact to the BPS is unique and should be evaluated on it's own merits
  - Active monitoring solutions include:
    - Military grade fencing with intrusion detection and actively monitored CCTV to validate the intrusion
    - Typical chain-link fence with intrusion detection, with the addition of cameras to validate the intrusion detection
    - Video motion detection and intelligent video to detect and respond to breaches in the facility
    - Security personnel assigned to the specific substation
    - Roving security staff have been used by entities, however feedback indicates this is not an effective solution. While the security person was at another site, the thieves broke in, and were out before the security patrol returned

Existing Facility Upgrades (cont)

- Consider potential intent
  - Copper theft can be used as a potential "cover" for other malicious activities
    - If there is a substation break in, we generally assume it is for copper theft.
      - Copper theft happens on such a frequent basis we may assume that copper theft was the ultimate goal
    - What if the copper theft is "cover" for reprogramming relays or other harmful actions?
      - If a substation has a break in with copper theft, consider evaluating the state of all equipment within the substation, especially if the control house or control cabinets were potentially breached

Existing Facility Upgrades (cont)

- What is Active Monitoring?
  - If you have immediate intrusion detection and
  - You have a way of visually validating the person's actions while that person was in the substation
- Active Monitoring – Aurora
  - Active monitoring of intrusion detection can be ***part*** of the mitigating measures for Aurora
    - Per the NERC Alert and guidance on Aurora, true active monitoring can be used not only for copper theft, but also a mitigating measure for Aurora
    - Using active monitoring, you can take credit for part of mitigating Aurora and prevent copper theft. Refer to NERC Alerts on Aurora

Existing Facility Upgrades (cont)

- Post event monitoring solutions include:
  - Video camera systems with recording capability Feedback from utilities indicate damage had been already been done by time the recording was reviewed, and substation repairs were needed. Most wore ski masks to prevent identification. In some cases the cameras were also stolen
  - Data marking devices, such as micro-dots. These were used in conjunction with law enforcement to identify the copper at the recycler. Deterrence was also a factor due to signage posted indicating all copper was marked

Existing Facility Upgrades (cont)

- Alternative metals used in place of copper for grounding straps
  - Many companies have implemented this solution with successful deterrence. The concern exists that if the thief knows the grounding straps are worthless, they may turn to the next easiest copper source – control cables. Reports from some utilities indicate when thieves were caught in the process of stealing copper, the thieves conveyed their strategy to the utility. No matter what, the thief was going to leave the substation with something they could sell. This leaves the control cables as a very persuasive option since the grounding straps had no value – the thief simply had to open the control cable covers to obtain a product they could sell. Due to the severe impact to the BPS with cut control cables, concern remains using non-copper alternatives for grounding straps

General Best Practices

- The following list of protective measures are inexpensive and should be used no matter what other methods you use
  - Develop a relationship with local law enforcement
    - Putting a face to a name has helped in all areas
    - Provide law enforcement with a tour of your facilities, including safety precautions. They may be reluctant to go inside the fence not understanding what is safe and what is not, including your basic company policies
  - Train your staff
    - Raise awareness of the impacts of copper theft, including the dangers and potential outages
    - Train your staff on what to tell the community to look for. This increases the community awareness of what could happen due to copper theft and increases the number of people aware of what is happening to them locally

General Best Practices (cont)

- Develop a relationship with your local scrap dealers
  - Train them what to look for, and who to call
  - Institute of Scrap Recycling Industries (ISRI) has an active program to raise awareness among reputable scrap dealers, and has a reporting tool on their website: www.ISRI.org
- Consider a rewards program for tips leading to arrests
  - Many utilities have adopted this approach, and has been successful at increasing the number of copper theft arrests. One utility uses a food reward for tips. It also encourages others that the industry does care about keeping their lights on
    - Generally, a brochure is included with the utility bill or information on the reward program is available online
  - Rewards programs provide a positive image to customers that the utility industry has the customers best interests in the forefront – ensuring reliability and keeping the lights on

Next Topic

- Metal Theft as a Global Issue – Presented by: Chris Hearn, British Transport Police

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Metal Theft as a Global Issue

Chris Hearn – United Kingdom Law Enforcement

November 28, 2011

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Introduction / Bio



DEMAND,DEMAND,DEMAND



- 2000 – US$2,609,162
- 2010 – US$18,264,667
- 2005 – US$5,708,421
- 2011 – US$20 million
- US$586 billion infrastructure investment - 2008
- 10 million apartments & US$405.7 billion investment - 2011

‘NEED FOR MORE COPPER IN THE NEXT 20YRS THAN THE LAST 110YRS’

METAL PRICES

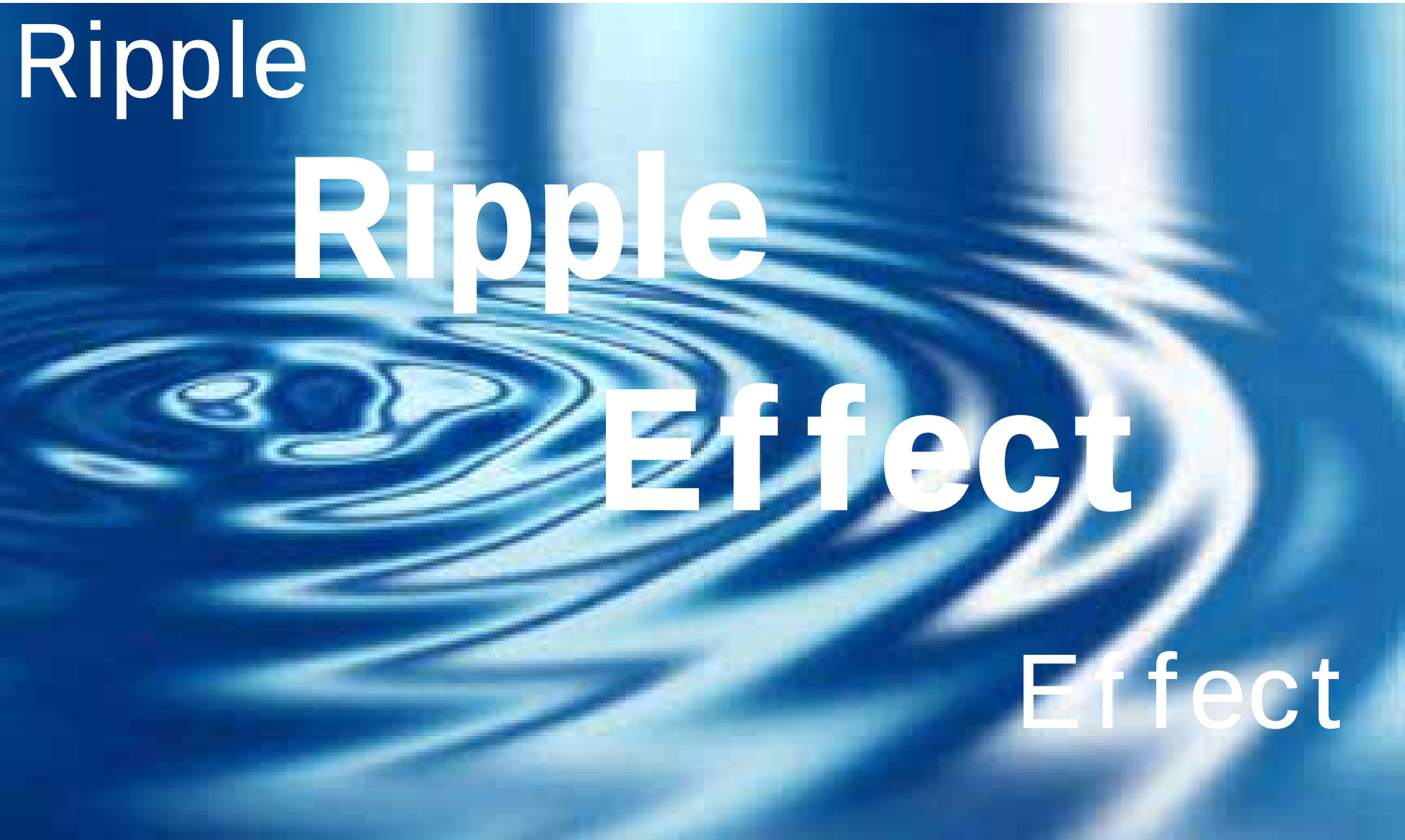
- **COPPER:** £6,296 (Highest Level Ever) 3/1/2011 (Predicted rise to £7,500 a tonne)
- **LEAD:** £1,699 (£200 – 300 in 2006) 20/7/2011
- **ALLUMINIUM:** The New COPPER

400,000 Tonnes shortfall against demand 2011

CHINA SYNDROME



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THE NEWS

- Canterbury Hospital, Manchester Shopping Centre
- Castleford houses explode – July 2011 (see Figure 2)
- Fatalities across UK & injuries to Police
- Doncaster -Village flooded (see Figure 3)
- GEORGIA: 75yrs woman shuts down Armenia looking to steal copper.
- South Africa - £445 million problem
- Gatwick & Stansted UK International Airports power failure
- Strategic Military Establishment on standby generators
- HEYSHAM – 250 church memorials attacked
- BEXLEY in London – Power cut affects 94,000 people (£24 million)



Figure 2: Castleford Houses explode



Figure 3: Doncaster Village Flood

Substation After Copper Theft



KEY RISKS

- **Injuries and Fatalities**
  - Three UK Police officers seriously injured
  - Average two offenders a month, killed or hurt (Leeds, Basildon, South Wales, Manchester)

- **Critical Incidents**
  - METPOL – Airwaves lost 2010.
  - South Wales – No trains in/out 2011.
  - 16yrs old dead in West Yorkshire July 2011.
  - **OLYMPICS 2012 issues already £1 million plus issue**.

- **Economics**
  - UK economy **US$1.1billion** (not confirmed) but likely higher.
  - Replacement Costs, Collateral Damage, Loss of Production
  - Service, Payments, Reputation.
  - **US$7.9 billion plus industry**.
  - BMRA – Members handled **US$1.9 billion** in cash in 2010.

Table 1: Metal Theft Incidents January – April 2010

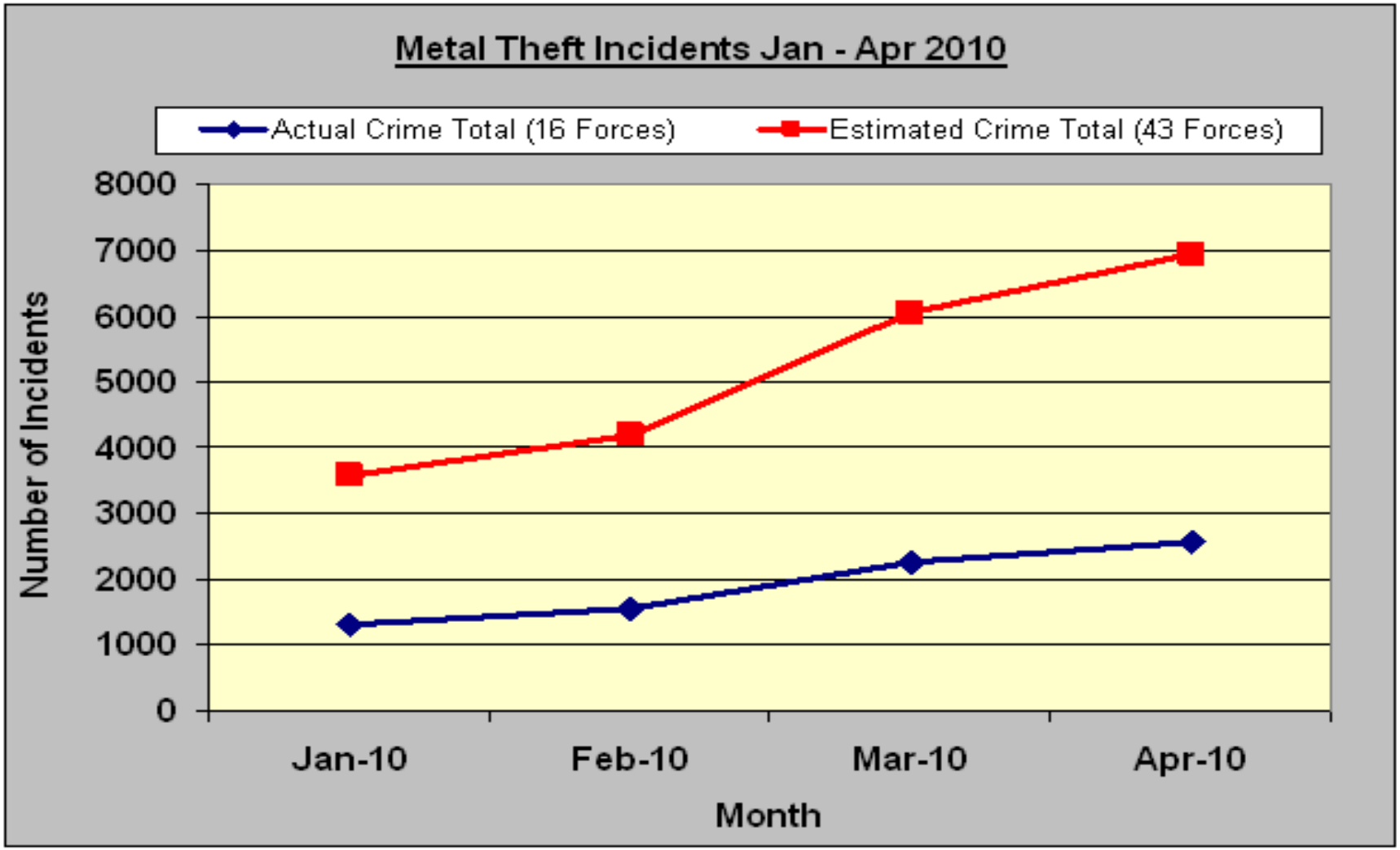


Table 2: Incidents by Company January – July 2011

Incidents by Company: JAN – JULY 2011	
British Telecom	780
CE Electric	943
E.ON	207
UK Power Networks (EDF)	942
Electricity North West	201
National Grid	86
Scottish & Southern Energy	35
Scottish Power	393
Virgin Media	440
Western/Midland Power Distribution	402
Grand Total	**4429**

NATIONAL RAILWAY THEFT STATISTICS

- National projection for 2010/11 is **477,579** delay minutes
- Equates to **10,976** trains
- Current trends indicate 2013/14 **14,458** trains
- Cost of cable theft is likely to be around **US$30.2m** per annum by 2013/14
- Two incidents alone cost a total of **US$2.2m**.
- LNE have up to **40** 'live' cable thefts a day



DISTRIBUTION PROCESS

STOLEN METALS

SCRAP DEALERS
Tier 1, 2 & 3

RECYCLING PLANTS
Smelters / Granulators

CONTAINERS
National & International







Local Offenders

- **Degree of organisation (spotting, stripping and cutting cable)**
  - **Teens and Adults**
  - **Small quantities and prolific**
  - **Lead, manhole covers, traffic signs etc…**
  - **Rudimentary techniques**
  - **Migrated from other acquisitive crime**
  - **Eastern European emergence**
  - **Drug dependency**
  - **Travel up to 7 miles – wheelie bins, shopping trolleys and taxis**
  - **Economic issues**









Organized Criminal Groups (OCG's)

- Travelling fraternity
- Highly organised
- Vehicles used - Transits, HGV with HI-AB capability
- Travel great distances to commit crimes (Wakefield – Scotland)
- Deception / destruction techniques
- Large quantities
- HGV Hijackings
- Ownership & Symbols



Strategic Points



- SMD Strategy
- CSI Strategy
- Media Strategy
- Minimum Standards
- Training & Awareness
- Metal Identification
- Dedicated Resources
- National FUSION Intel Unit
- National Taskforce
- Crime Coding (since 2006)
- SIRS (since 2008)

METAL THEFT TACTICS

- Multi Agency approach
- National 'Fusion Centre'
- Identify SMD's and visit them (complete forms).
- Offender Management
- DSU – CHIS/Confidential Source
- Disruption Tactics
- BTP – Metal Recovery Scheme
- Escalation/Pier Plans
- Planned operations (multi agency)
- Assess and monitor
- LEGACY ISSUES



WORKING TOGETHER

- Staff Training & Deployment.
- Impact Statements.
- SIRS 2 and Police Liaison.
- 'Codes of Practice'.
- Short Term - SMD's – Posters, Catalogues, visits.
- Medium Term – Metal Identification (existing) & Legislation.
- Multi - Agency
- Long Term – Manufacture/design.
- **Crime Prevention 'Best Practice Guide'**



Next Topic

- Entity Copper Theft Solutions – Presented by: Brian Smith, Progress Energy.

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Entity Copper Theft Solutions

Brian Smith, Progress Energy

November 28, 2011

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What is Needed to Create Copper Theft Issues?

- Person with criminal intent or motivation to steal
- Obtainable reward
  - Increased copper prices = valuable target
- Window of opportunity
  - Quick, easy targets
  - Low risk with high reward
- Victim(s)

Progress Energy Targets

- Operations Centers
  - Unstaffed after normal business hours
  - Copper reels on the back of bucket trucks
  - Scrap bins
- Substations
  - Unstaffed the majority of the time
  - Remote locations
  - Copper grounds

Recent Copper Threat Metrics

- 2009 – 130 Investigated Copper Thefts
- 2010 – 111 Investigated Copper Thefts
- 2011 – 117 Investigated Copper Thefts
  - Direct relationship between cost or value in copper and the number of thefts experienced
  - PE has experienced an average loss per theft of $3,800 not including loss revenue
  - Estimated PE Copper Loss in past 2.5 years = $1,360,400

How Do We Mitigate the Vulnerabilities?

- Harden the Target - Create an environment to make it difficult to steal
  - Lighting
  - Fencing
- Reduce the Opportunity
  - Remove or conceal targets
  - Increase traffic or occupancy
  - Law enforcement patrols
- Add Risk to the Reward
  - Increase the chances of being caught

Mitigation Options

- CCTV
  - Power and network infrastructure
  - Costly installation
  - Resources required to monitor
  - Video of crime being committed but no detection
  - Minimal deterrent
- Intrusion Detection
  - False alarms
  - Costly installation
  - Questionable responses from law enforcement

Wireless Video / Intrusion Detection Systems

- Wireless
- Self-Powered
- Portable
- 128 Encryption
- *Cost Effective*



What is this System?

- **It is NOT surveillance**
  - Event-based video/intrusion detection security system
  - Cameras are on only during an alarm event
- **Wireless & Battery Powered**
  - No A/C power , phone or network connection
  - Cell reporting to Command Post or Monitoring Station
- **Fast Installation/Deployment.**
  - No holes, no wires, and no waiting

How Does it Work?

Radio Transceiver

- 2 way encrypted
- Self-powered
- No AC connection
- 4 year battery life



Motion Sensor

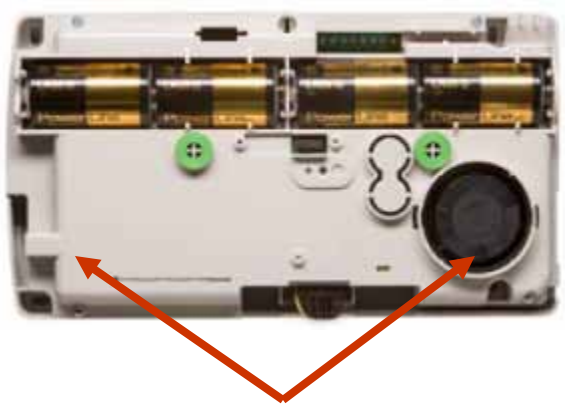
Night vision digital camera

Infrared illuminators

FAQs

- Range
  - RF transmission
    - 2,000 foot “line of sight” range between devices/panel
  - Motion detection to 40 feet
  - Night vision to 20 feet
- Battery Life
  - Approximately 4 years (Varies depending on activations)
  - Lithium AA
- Video
  - compressed 200K MPEG 1 for universal reading
  - 240 x 320 resolution, 15 frames/sec.

Battery Powered









Primary and Back-up Battery Power Systems on Panel





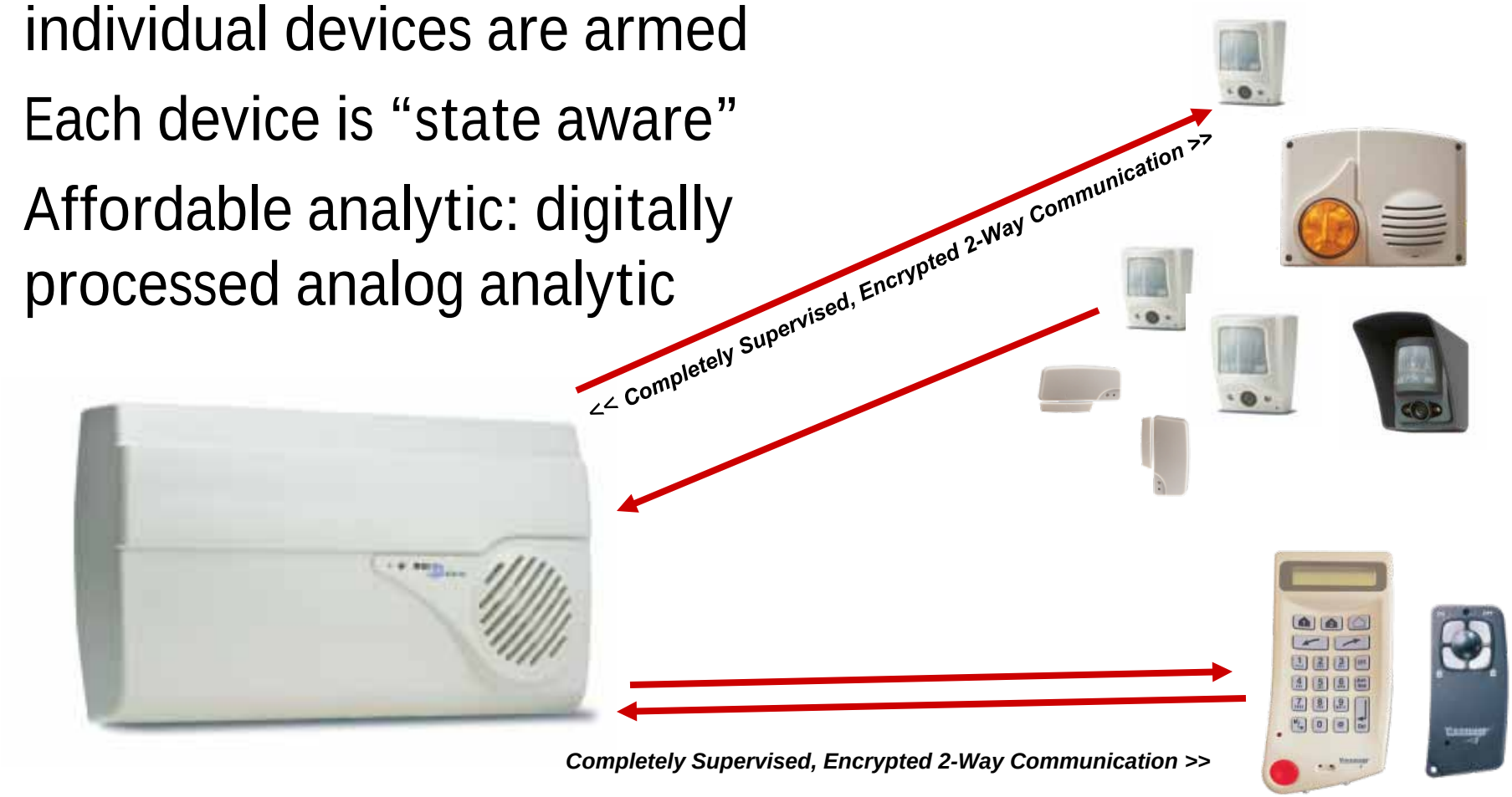






Intelligent Field Devices

- The Panel is not armed: individual devices are armed
- Each device is “state aware”
- Affordable analytic: digitally processed analog analytic



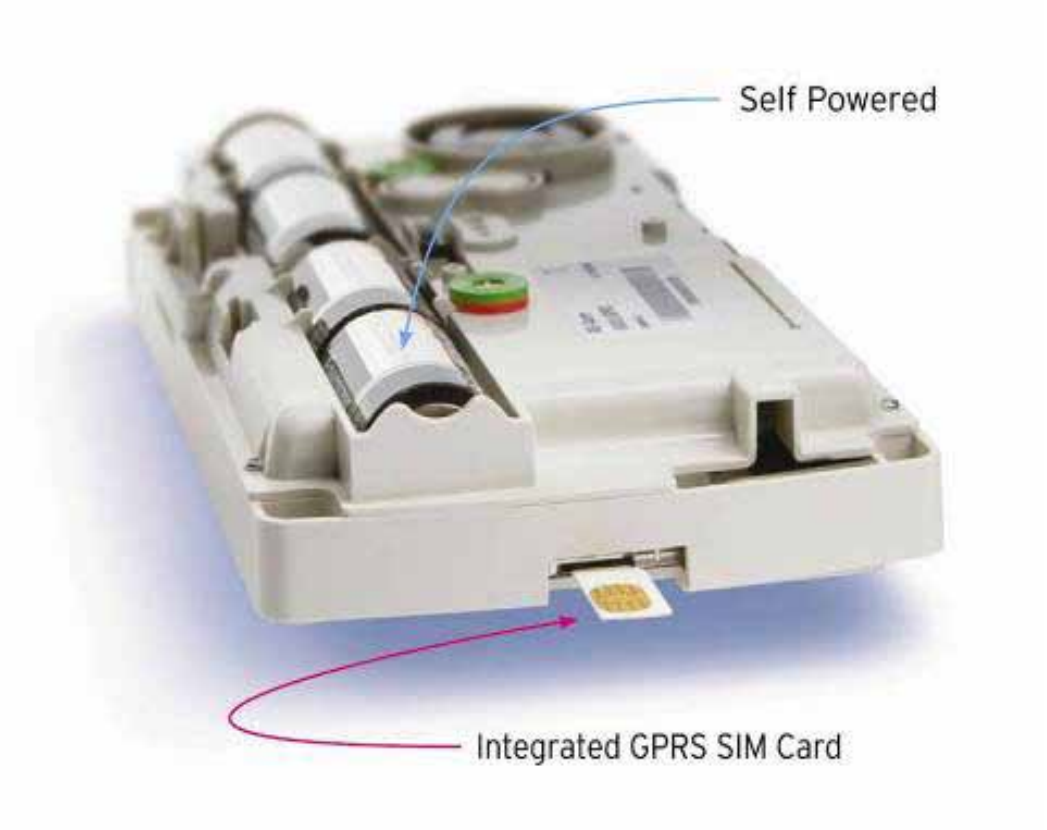
Reporting and Communications

- System features combinations of 3 methods of communication (PTNS plus 1 or 2)

1. Optional Internal GPRS Cell
2. Optional Ethernet - Intranet and Internet
3. Telephone PSTN Dial-Up

GPRS Cell Communication

- Certified ATT Partner
- SIM cards



System Wiring Diagram

- Keypads
- P-Cams
- Exterior Siren
- Interior Siren
- Contacts
- Key-Fobs
- Smoke
- GPRS Communicator



Indoor/PIR Camera

- Sensor Reliability - False Alarm Suppression
  - § IR Energy Complications
    - o Sunrise/Sunset
    - o Reflective Energy
    - o Spurious IR Sources
  - § Environmental Complications
    - o Weather (snow, sleet, rain)
    - o Small Animals
- Camera Optical Complications
  - § Lens Obscuration
  - § Illumination



Outdoor PIR/Camera

- Outdoor/Harsh Environment
  - Transceiver/sensors/illumination/camera from -20F to +140F
  - Mechanical design sheds water/dust
  - NEMA Enclosure survives direct water jet
  - Special Lens Coatings shed dust and water
- Analytics & Compensation
  - Adaptive PIR sensitivity from -20F to +140F
  - Dynamic filtering of outside light/energy
  - Automatic Ambient Light Change Compensation
  - On-board illumination to 40 feet
  - Adaptive Background and Target/Time/Motion Algorithms
- Delivers >3,000 videos on one set of batteries



Spread Spectrum

- Improved transmission/reception in difficult environments
- Resistance to jamming
- Deterrence to hacking and eavesdropping
- Easy installation
  - PE has customized a mounting gimble for use on poles

Bi-directional

- Every device is supervised by control panel every 8 minutes to validate communications and status.
- Enables capture of Serial #, manufacturing date, firmware and revision from each device by the panel with no manual input during installation.
- Facilitates installation with Roaming Keypad for range testing, validate detection, device locator.
- Enables AES encryption to secure communications and prevent hacking.

Encryption

- Encryption Key between devices is changed every second.
- Eliminates eavesdropping.
- Eliminates hacking into the panel or devices.
- Eliminates crosstalk and interference from other alarm systems/devices in close proximity and overlapping RF.

Progress Energy Success

- 146 interrupted copper thefts since deploying systems in 2009
- Estimated averted loss = $544,800 (excluding saved revenue)
- Apprehensions
- Prosecutions
- Retributions

Substations





Substations









Substations





Warehouse





Storage / Containers





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Panel Question and Answer



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Presenter Information

November 28, 2011

RELIABILITY | ACCOUNTABILITY






Ralph Anderson, CRISC, RC

NERC CIP Training and Exercise Coordinator. Contact: ralph.anderson@nerc.net, (321) 247-5687 (Work), (609) 218-3395 (Cell)

Ralph Anderson is the CIP Training and Exercise Coordinator for the North American Electric Reliability Corporation (NERC) joining NERC in August 2008. In this capacity he is responsible for conducting training both internal and external to NERC as well as coordinating drills and exercise both at the national level and those sponsored by NERC. He also provides technical expertise on the grid as needed for various government agencies. Ralph has over 27 years experience in Power System Operations, compliance, training and planning having worked at Florida Municipal Power Agency (Regulatory Compliance Officer, Transmission Planning Manager), SERC Reliability Corporation (Senior Compliance Auditor), Midwest ISO (Senior Operations Manager, Reliability Coordinator), Exelon Corporation (Shift Manager Bulk Power Operations, Distribution Systems Operator, Project Management and 12 years in nuclear operations, maintenance and procedure writing). Ralph has a BS (Management), from the University of St. Francis in Joliet, IL, and AAS (Mechanical Technology) from Joliet Junior College, Joliet, IL. He is also certified as a Reliability Coordinator and had has maintained that that certification since 1999. He is also certified in Certified in Risk and Information Systems Control (CRISC) with the ISACA. Prior to joining NERC, Ralph was very active in the American Public Power Association (APPA), and represented the state/municipal sector on the NERC Operating Committee. He is also a member of the Institute of Internal Auditors.

Chris Hearn

British Transport Police - National Metal Fusion Intelligence Unit & Operational Team - Protective Services

Contact: christopher.hearn@btp.pnn.police.uk, 020 7084 5442 (48442) (Work), 07920 856313 (Cell) Note: review dialing codes to the UK, varies by country.

Chris has 19yrs military background behind him and a further 15 yrs Police service having joined the British Transport Police in 1996. He is a career detective having worked in general duties, squads and Major Crime.

Since 2006 Chris has held a portfolio in Metal Theft for BTP which has covered training, intelligence, strategic and operational policing. He holds key roles and has extensive knowledge of the subject with International articles and presentations being given to both law enforcement and industries.

Chris sits on the National ACPO Metal Theft Working Group and the similar Network Rail Group he has day to day responsibility for the National OP LEOPARD FHQ operation team and the newly formed National Metal Theft 'Fusion Intelligence Unit' (industry and police working together). He is involved in cross industry and government policy and legislation review from FHQ in Camden, London.

Barrie Millet

E•ON Head of Business Resilience Contact: Barrie.Millett@eon-uk.com, 011 44 2476 192000 (Work), Note: review dialing codes to the UK, varies by country.

Barrie Millett has over 20 years security leadership experience, from policy and strategy development, tactical implementation of security and crisis management initiatives and development of effective fraud risk management programs. Following service as a Royal Marine Commando successfully transitioned in to the corporate environment, gaining specialist corporate security risk management experience with National and Multi National organizations holding senior security positions with Fraud Management Limited, Britannia Building Society and GE. Barrie is currently employed by E.ON UK as Head of Business Resilience, with responsibility for all security, business continuity, crisis management and fraud risk management programs. He has successfully managed a number of risks to the business including sustained direct action from various single issue action groups, effectively minimizing business interruption. A strategic results oriented security risk management leader with a proven track record of success in developing and implementing risk management strategies with a demonstrated readiness to make decisions and take the initiative in crisis situations, awarded several Leadership Awards for strategic development and implementation of a number of global key initiatives in diverse geographical locations. He is involved in a number of security associations and forums including; past Chairman of the ASIS International UK Chapter 208, a member of the Security Institute and sits on the UK Energy Security Managers Forum. Barrie is a risk management champion who ensures that "Business Resilience" becomes a key business enabling strategy.

Brain Smith, CPP, CHS

Lead Security Specialist, Progress Energy-Corporate Security. Brian.Smith@pgnmail.com

Mr. Smith has over twenty (20) years of combined experience in security system design, security system installation/service, security management and security consulting. Since 1999 he has worked directly with power/utility clients throughout the East Coast such as: Progress Energy, Dominion Resources, Duke Energy, Orlando Utilities Commission, SCANA, Fayetteville Public Works and NASA. He has earned Applied Associates degrees in both Business Administration and Electronics Engineering. Mr. Smith has served in roles such as Project Manager, Project Engineer and Consultant for numerous industrial security projects. He developed and successfully operated an electronic security systems company for 6 years that specialized in CCTV, Access Control and Intrusion/Fire detection systems. His security experience includes the areas of utility companies, manufacturing, banking, vulnerability analysis, and security surveys. He has extensive liaison experience with local Fire Marshals, installation vendors, and general/electrical contractors. Current primary responsibilities are to design, specify, and project manage the installation of complex electronic surveillance, alarm and access control systems and manage all physical security systems and programs for Progress Energy. He is a Certified Protection Professional (CPP) and member of the American Society for Industrial Security. He has also achieved a Certification in Homeland Security (CHS). By qualifying with extensive experience in directly protecting portions of the nations critical infrastructure, Water Treatment and Electrical Utilities, the American College of Forensic Examiners Institute granted him a Level I certification. This high level certification demonstrates Mr. Smith's knowledge and expertise in physical security as it applies to Homeland Security.

Matt Stryker

Manager, CIP Compliance Monitoring , SERC Reliability Corporation. Contact MStryker@serc1.org, Office - (704) 494-7773, Cell - (704) 975-9326

Matt Stryker is the Manager of CIP Compliance Monitoring at SERC Reliability Corporation, a nonprofit corporation responsible for promoting and improving the reliability, adequacy, and critical infrastructure protection of the bulk power system in all or portions of 16 southeastern and central states. He serves as an Audit Team Leader or team member during audits of compliance with NERC Reliability Standards in the SERC Region.

Previously, Mr. Stryker held positions as an Associate Compliance Auditor, CIP Compliance Auditor, and Senior CIP Compliance Auditor at SERC Reliability Corporation. Prior to that, Mr. Stryker was the Financial and Operations Manager for a campus ministry in Puebla, Mexico working for CMF International. Prior to that, he was employed by IBM Global Services in Atlanta, Georgia as a Network Support Engineer and as a database designer.

Mr. Stryker has a BS in Management from Georgia Tech with a concentration in Information Systems.

From: Kimberly Mielcarek
To: Kimberly Mielcarek
Subject: NERC announcement - New Contact Information for DC Office
Date: Thursday, December 15, 2011 4:07:11 PM

Announcement

New Contact Information for NERC DC Office

WASHINGTON, DC – Beginning December 19, the North American Electric Reliability Corporation (NERC) will be located in new offices in Washington, DC. The new office address is **1325 G Street NW, Suite 600, Washington, DC 20005**. The main switchboard number is **202-400-3000.** All DC office phone numbers will be changing, but emails and cell phone numbers will remain the same. To reach NERC DC employees, contact the main switchboard, send email or use employee cell phone numbers.

The DC move was part of NERC's office relocation strategy, which began in 2010, and included moving NERC headquarters to Atlanta. The relocations were made with long-term goals in mind – including better personnel recruitment and retention; easier access by industry for meetings and conferences; and to strengthen key relationships with industry and government partners. The move to Atlanta was completed in June.

For more information on the DC office, please contact Alicia Wade.

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3-Month CEI Status Update

Industry Webinar

December 13, 2011

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Agenda

1) Progress of CEI
2) Overview of FFT experience to date
3) Reporting information on reliability issues
4) Preparation for 6-month filing with FERC

Initial FFT Filing

- Docket No. RC11-6: Petition for Approval of New Enforcement Mechanisms; Initial Informational Filing of FFTs
  - First group of FFT Remediated Issues
    - 117 total: 62 Operations/Planning Standards/55 CIP Standards
  - No action requested on individual FFT Remediated Issues
  - Report back to the Commission and industry stakeholders at six months and one year following initial filing
  - Comments were filed on October 21, 2011

Additional Filings under CEI

- Second group of FFT Remediated Issues and second Spreadsheet NOP violations were filed October 31, 2011
  - Docket No. RC12-1: 82 FFT Remediated Issues
  - Docket No. NP12-1: 31 in Full CIP NOP
    - FERC issued Notice of No Further Review on November 30, 2011
  - Docket No. NP12-2: 46 in Spreadsheet NOP
    - FERC issued Notice of No Further Review on November 30, 2011

Additional Filings under CEI

- Third group of FFT Remediated Issues and second Spreadsheet NOP violations were filed November 30, 2011
  - Docket No. RC12-2: 50 FFTs
  - Docket No. NP12-5: 60 Spreadsheet NOP violations
  - Docket Nos. NP12-3 and NP12-4: 21 Full NOP violations
- NERC expects to file additional FFTs, Spreadsheet NOPs, and Full NOPs on December 30, 2011
- NERC expects to make six-month and one-year informational filings with FERC

CEI Processing Statistics

	NOP Violations	FFTs	Total Filed with FERC
September	119	128	219
October	48	133	159
November	44	45	131
December	123	80	

CEI Processing Statistics by Region

	September NOP/FFT	October NOP/FFT	November NOP/FFT	December NOP/FFT
FRCC	12/30	0/25	0/2	0/16
MRO	0/24	1/9	0/11	1/26
NPCC	0/2	0/4	0/7	7/0
RFC	58/8	15/17	29/14	21/19
SERC	0/22	0/2	0/3	2/2
SPP RE	8/24	0/8	0/6	12/3
TRE	0/12	0/13	0/1	17/10
WECC	41/6	32/55	15/1	63/1
NCEA	0/0	0/0	0/0	6/13

Discovery Methods of Filed FFTs

- Filed September 30, 2011
  - Self-Report 46%
  - Audit 39%
  - Spot Check 8%
  - Self-Certification 7%
- Filed October 31, 2011
  - Self-Report 60%
  - Audit 26%
  - Self-Certification 12%
  - Spot Check 6%

Discovery Methods of Filed FFTs

- Filed November 30, 2011
  - Self-Report 60%
  - Self-Certification 18%
  - Spot Check 16%
  - Audit 4%
  - Periodic Data 2%
- Percentage of self-identified FFTs is increasing

Caseload Processing

- In first three months, 50% of issues filed were FFTs, 35% were in Spreadsheet NOPs, and 15% were in Full NOPs
- In five of the last six months, the ERO has processed more violations than it has received
  - More have been going out than coming in
- In 2011, caseload projected to increase by less than half of the increase in 2010

Determination of FFTs

- Regional Entities have the responsibility for determining possible violations for FFT treatment
- Registered Entities can increase chances of FFT treatment
  - Timely identification and fixing of reliability issue
  - Timely self-reporting
  - Complete reporting of mitigating activities
    - Some regions may still require mitigation plans for an interim period

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Compliance Enforcement Initiative:

GUIDANCE FOR SELF-REPORTS

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Submitting Self-Reports

Registered Entities are encouraged to provide Self-Reports of potential noncompliance with NERC Reliability Standards as promptly as possible.

A Self-Report should include sufficient information to assist the Compliance Enforcement Authority to make an informed decision regarding the proper disposition of the matter.

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Self-Reports:

What to include?

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Self-Reports: Basic Information

Nature of the Potential Noncompliance

- What, Why, When, Where, How
- Duration: start and end dates
- Reliability Standard requirements at issue
- Time horizon of the potential noncompliance
- Was the potential noncompliance related to documentation, performance or both?

Self-Reports: Discovery

Discovery

- How was the noncompliance discovered?
- Who discovered it and when?
- Self-evaluation, internal audit, or ICP? Result of an investigation or in preparation for or during an audit? Discovered during an event or operational occurrence?
- What time period elapsed between discovery and reporting? Explain gaps.

Self-Reports: Scope of Non-Compliance

Scope (Extent of Condition)

- Did similar conditions or similar events occur at any of the Registered Entity's other facilities or those of its affiliates?
- Is this a repeat Violation or repeat Remediated Issue?

Self-Reports: Cause of Non-Compliance

Cause

- Were there extenuating circumstances?
- Was it the result of intentional, negligent or inadvertent behavior or action?
- Was the Registered Entity attempting to comply in good faith?

Self-Reports: Remediation

Mitigation

- What activities have been taken or will be taken to correct the noncompliance?
- What is the status of mitigation activities?
- What is the timeline for completion?
- What will prevent recurrence?
- Describe above and beyond actions

Self-Reports: Assessing Risk

RISK

- What is the potential and actual risk and harm to the reliability of the bulk power system?
- What factors mitigated the risk?
- What were the system conditions during the event?
- What are the size, nature, and location of the facilities at issue?
- Were there were any misoperations, system operating limits, or interconnection reliability operating limits?

Self-Reports: Who did what

Personnel Involved

- Include the identity of employees involved
- What was the role of senior management with respect to the potential noncompliance?
- Did senior management actively participate and encourage employees to provide complete information?

Self-Reports: ICP

Internal Compliance Program

- Describe the internal compliance program
- When was it established?
- What improvements have been implemented as a result of the potential noncompliance?
- If the ICP was in place at the time of the potential noncompliance, explain whether the ICP could have prevented the potential noncompliance.

Self-Reports: Supporting Evidence

Other

- Provide or list all relevant documents and evidence in support of the Self-Report and issues discussed above

6-Month Status Report to FERC

- Demonstrable reliability benefits of FFT
  - Incentive to find and fix possible violations more quickly
  - Less time spent in enforcement = More time spent ensuring reliable operations
  - Expedited reporting of mitigating activities to public
- Will look for supporting evidence from Regional Entities
- Soliciting Registered Entity feedback via NERC Member Representatives Committee

Conclusion

- Registered Entity support of FFT has been valuable
- Regional Entities are supporting FFT
- NERC is continuing to work with Registered Entities and to engage in outreach efforts to ensure successful implementation

The ERO is on top of reliability.

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Lesson Learned

Plant Operator Training to Prepare for a Winter Weather Event

Primary Interest Groups

Generator Owners
Generator Operators
Balancing Authorities

Problem Statement

During a severe winter weather event, human performance errors caused generating units with a combined output of over 700 Mw to trip, which contributed to the Reliability Coordinator and Balancing Authority having to implement rolling load sheds.

Details

The Generator Owner/Generator Operators (GO/GOP), using detailed checklists, performed their annual weatherization program on their plants in the Fall/Winter of 2010 to prepare for the cold weather. As the weather forecast began calling for freezing temperatures, the plants implemented pre-defined freeze protection procedures. These procedures are specific to each plant and unit and include tasks such as ensuring that generating equipment is protected and ready for a freeze event, heaters are fueled and ready to operate, the station has spare food and accommodations for staff, and that subsidiary plant equipment is protected. During the cold weather event, the plants experienced temperatures below freezing for 65 hours and wind chills as low as in the single digits. At two plants, four units tripped due to human performance errors. The human performance errors experienced by these two plants were:

- Frozen instrument sensing lines caused false instrumentation signals to be transmitted. Operators did not recognize that data integrity had been affected which led to incorrect operator decisions and actions.
- Plant operators, who were manually operating units, made mistakes by not compensating for the colder temperatures.
- Plant changes were made in violation of the plant's tag lockout procedure

The frozen critical instrument sensing lines were thawed and other measures were implemented to correct the errors and return the generation to service. The generation was back online later in the day but missed the morning peak.

Corrective Actions

The GO/GOP evaluated their plant training programs and addressed the human performance issues. They incorporated training, which improved the situational awareness of operators, by informing them of the additional unit parameters which should be cross referenced with other critical system measurements to aid them in their ability to identify inaccurate instrument measurements. The training organization also evaluated and implemented changes in each plant control room and unit console to minimize the potential for human performance error.

Lessons Learned

To maximize plant operator human performance during cold weather operations, GO/GOPs should consider the following:

- Have operators trained on the winter freeze protection plan and the emergency winter operation plan to provide them better insight into the plant operation during winter events including awareness of the capabilities and limitations of the freeze protection monitoring system.
- It is likely that operators will accept critical metering as always being accurate, as it usually is reliable most of the time. Hence, there is a need for data integrity training and reminders that critical unit data may be inaccurate and should always be correlated with other data to help determine its accuracy. Also, procedures should be developed and practiced where operators are dependent on manually receiving critical operating data to simulate conditions where parameter sensing transmitters malfunction or freeze. Simulators would be ideal to provide this training.
- Plant operators communicate with many other entities and during a period of high stress operations events, common with severe winter weather, operators will be communicating with other entities such as Balancing Authorities (BAs), which are also experiencing high stress conditions. Due to possible miss-communications, plant operators should ensure, just as with normal communications, the use of 3-way communications protocol is used when receiving or giving instructions.
- During high stress situations such as capacity emergencies, human performance errors could occur due to terminology differences between entities. For example, a BA communicates to its Transmission Operator (TOP) to "shed 500 Mw of load" from the system. To accomplish this, the TOP removes power from enough customers to reduce 500 Mw of load on the system. This terminology has a different meaning to plant operators. In many cases, if a plant operator received the same message, it would be interpreted to mean to shed their customer load by reducing their generation output 500 Mw. BAs must be very careful in using this terminology. If such terminology is used where both TOs and GOPs see the same message, the BA should consider adding the verbiage "For plants – do NOT reduce generation".
- If staff cannot be housed near the plant, GO/GOPs should ensure that additional staff such as Operations, Maintenance and Engineering personnel, who are trained to be able to perform certain critical jobs, are at the plant prior to the onset of an extreme cold weather event and throughout the extreme cold weather. Human performance errors increase dramatically if personnel have to perform duties which they have not been trained to do and which are normally done by others.

For more information please contact:

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Source of Lesson Learned: Texas Reliability Entity

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing reliability standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

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Lesson Learned

Plant Onsite Material and Personnel Needed for a Winter Weather Event

Primary Interest Groups
Generator Owners (GO)
Generator Operators (GOP)

Problem Statement
A 700 MW generating plant, despite having installed new freeze protection to maintain the plant's operability to 40 degrees F during 0 degrees F conditions, contributed to a balancing authority (BA) having to implement load sheds because it could not keep generation online during 0 degrees F conditions because of critical components freezing.

Details
Before a cold weather event, the plant personnel discussed the forecast for the on-coming cold weather during plant staff meetings, advising everyone to remind their teams to prepare for the cold weather of longer duration than the plant had experienced before. Temporary enclosures were constructed in areas subject to wind. Portable heaters and tarps were placed where critical equipment, instrumentation and/or piping was located. The fuel level in the kerosene heaters was checked and fuel was added as needed. Heat tracing panels were checked and heat tracing was verified to be functional. A "tools down" order was communicated to all plant personnel to prevent any problems associated with non-emergency maintenance work. This order included no changes or tuning to be done on the plant control system. The "Work Force Disruption Policy" was initiated and essential maintenance and operations personnel were confirmed and scheduled for day and night shifts staying at the plant site to avoid delays in personnel getting onsite. Operators and the plant water technicians increased rounds. Physical surveys of all piping and tubing insulation were conducted and deficiencies were corrected. This continued throughout the event.

For several days, the plant experienced night time low temperatures of the middle teens, daytime highs of the middle twenties and wind chills as low as 0 degrees. Despite the precautions taken, a level switch and transmitter sensing line froze, resulting in low condensate storage level and a turbine trip just before 6:00 a.m.

Among the weatherization changes made to bring the unit back online were temporary insulation and drop lights which were wrapped around the units' low water level transmitters. Repairs were made to the level switch target guide and operations thawed the low level transmitter, insulated it and installed a 250 watt heat lamp on the transmitter.

After cleanup and resolving other issues which resulted from frozen equipment, the unit returned to service at 3:00 a.m. the next day.

Corrective Actions

The GO/GOP brought additional supplies in addition to those already on-site for winter operation, including over 1300 gallons of kerosene for heaters, over 40 more tarps, 750 feet of heat trace, ten hand-held propane torches and fuel, extension cords, etc. Additionally, the GO/GOP:

- Developed a Freeze Protection Task Team for continuous monitoring and evaluation of the Freeze Protection Procedure. Some of the responsibilities included prioritization of corrective actions taken and recommend permanent repairs.
- Contacted suppliers of prefabricated insulation covers to schedule an evaluation of current covers to confirm proper durability and functionality as well as have the suppliers make recommendations for improvements.

Lessons Learned

GO/GOPs should maintain a sufficient inventory of winterization supplies for each generating unit. These supplies should be on site and located near each generating unit for easy access. Items to have in stock that may need to be needed to increase freeze protection are:

- Extension cords
- Portable generators
- Insulation material and fleece blankets
- Electrical heat trace
- Heat guns
- Plastic rolls
- Heat lamps and portable heaters
- Copper instrumentation tubing
- Propane heaters and propane bottles
- Handheld welding torches
- Heat lamps

GO/GOPs should:

- Consider placing thermometers in rooms containing equipment sensitive to cold temperatures and monitor in order to be able to take action when temperatures fall below freezing.
- Consider having extra personnel at the plant site or in hotels near the plant so as to have the necessary personnel available to keep the plant operating and to minimize personnel having to travel roads icy roads.

- Evaluate their plant electrical circuits to insure they have enough capacity to handle electrical heaters. Those circuits with ground fault interrupters (GFIs) should be continuously monitored to make sure they have not tripped due to condensation.
- Drain any non-critical service water lines in anticipation of cold weather.
- Know the ambient temperature for which the freeze protection is designed.

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Lesson Learned
Transmission Facilities and Winter Weather Operations

Primary Interest Groups
Generator Owners
Generator Operators
Transmission Owners
Transmission Operators

Problem Statement
Unit 1 at a 1700 Mw plant was forced off line during a severe weather event due to the failure of the disconnect "B" phase switch.

Details
After a winter storm at a generating plant, the "B" phase disconnect switch connection started to arc in the plant switchyard. The Control Room was notified immediately and operations manually tripped the turbine and took the generator off line. It was found that the arc originated toward the pivot point of the switch just inside the contact region. The disconnect switch did not arc in the contact area of the switch. Once electricians removed the disconnect switch arm it was found to be full of ice. Under normal circumstances water should not be inside the disconnect switch arm. Water, which had ingress in the disconnect arm, froze during the cold weather, causing the weld on the end of the arm to crack and reduced the current carrying capabilities of the arm. This added heat to the area, which progressed to an arc.

Corrective Actions
To prevent reoccurrence, all three disconnect switch arms were replaced. The transformer side contacts were replaced on the "B" phase connection as well as the corona ring between the contacts and the insulators and the bottom corona ring. Each contact was verified with a visual inspection and an electrical test. The insulators on the "B" phase transformer side connection were tested. The insulators on the center pivot, which supports the switch arm, were also tested. All insulators tested to be good. Research of available industry technical documentation did not find any documentation on similar occurrences. The manufacturer was contacted and reported that they had not seen this type of failure. The manufacturer recommended drilling holes into the switch arm to eliminate water collection. This recommendation was completed by maintenance personnel. Other units at the facility have the same disconnect switches but did not experience the same issues. They were inspected and were changed per the manufacturer recommendations.

Lessons Learned
All plant and transmission electrical disconnect equipment should be inspected for areas where water could collect and freeze – especially in geographic areas not accustomed to freezing temperatures. Any

areas found with the potential to retain moisture should be modified as prescribed by the equipment manufacturer or by an adequate engineer design.

With regards to transmission and substation equipment, other lessons which the GO, GOP, TO and TOP should consider in their winter preparation plans are:

- Power transformers should have their equipment checked to ensure:
  - Control cabinet heaters are working correctly
  - Oil is at its appropriate level for the oil temperature.
  - Bushing oil levels are appropriate
  - Nitrogen levels are correct
- SF6 gas-insulated devices should be checked to ensure:
  - SF6 gas in breakers, current transformers and other electrical equipment is at the correct pressure and temperature to operate safely during extreme cold
  - Heaters (when so-equipped) and associated support circuits are functioning correctly
- The minimum operating ambient temperature should be known on all transmission facilities. This temperature should also take into account fire protection systems.

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ERO Compliance Monitoring and Enforcement Program

2012 Implementation Plan

Version 1.2

NOTE:
CMEP Implementation Plan and the 2012 Actively Monitored Reliability Standards List are posted at:
http://www.nerc.com/commondocs.php?cd=3

January 9, 2012

to ensure the reliability of the bulk power system

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ERO Compliance Monitoring and Enforcement Program

Reliability and accountability are basic tenets of the Compliance Monitoring and Enforcement Program (CMEP). The objective of the North American Electric Reliability Corporation (NERC) and the Regional Entities is to achieve the highest possible level of reliability for the Bulk Power System (BPS). NERC, as the FERC-certified Electric Reliability Organization (ERO), together with the Regional Entities, is accountable to government regulators and industry stakeholders. The CMEP is critically important in supporting reliability and accountability, since effective compliance is a necessary, yet insufficient, activity for assuring the highest levels of reliability. The CMEP covers not only monitoring and enforcement activities, but also education, training and informational activities designed to assist the industry in achieving and sustaining effective compliance and enhanced reliability. The CMEP also complements other critical ERO activities aimed at improving reliability such as: facilitating the industry in the development and improvement of Reliability Standards, providing reliability assessments, and identifying lessons learned from events analysis that can assist the industry in enhancing reliability. There is clear ERO and industry accountability for the development of Reliability Standards in accordance with the 2005 Federal Power Act[1] and FERC Order No. 672[2], which duly recognize the collective expertise, experience and judgment needed to develop and improve Reliability Standards. NERC continues to refine and improve the annual CMEP and Actively Monitored List (AML) by focusing its efforts and resources on those areas that pose the greatest risk to reliability of the BPS.

As a reminder to all Registered Entities, NERC Rules of Procedure (RoP)[3] state that all Bulk Power System users, owners, and operators are required to comply with all applicable ERO governmental authority-approved Reliability Standards at all times. Regional Reliability Standards and regional variances approved by NERC and the applicable ERO governmental authority are enforceable and apply to all Registered Entities responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the BPS user, owner, or operator is a member of the Regional Entity.

The CMEP is developed under Section 215(c) of the Federal Power Act[4] to establish and enforce Reliability Standards for the BPS, subject to review by FERC and in general accordance with the "Principles for an Electric Reliability Organization that can Function

[1] Section 215(d)(2) of the Federal Power Act located at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf
[2] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,*114 FERC ¶ 61, 104 (2006) at P 324 located at http://www.nerc.com/files/final_rule_reliability_Order_672.pdf.
[3] *See* Rules of Procedure, Section 401.2 at http://www.nerc.com/page.php?cid=1|8|169.
[4] *Federal Power Act, 16 U.S.C. 824o. a.3 (2005).* Located at http://www.nerc.com/fileUploads/File/AboutNERC/HR6_Electricity_Title.pdf

on an International Basis."[5] The CMEP is designed to improve reliability through the effective and efficient enforcement of Reliability Standards.

FERC Order No. 672 provides the framework for the ERO and its corresponding certification process. On July 20, 2006, FERC certified NERC as the ERO[6]. FERC regulations provide that an ERO must submit an assessment of its performance three years from the date of certification by the Commission, and every five years thereafter. On September 16, 2010 FERC recertified NERC as the ERO[7] following the three-year assessment.

To help fulfill its responsibilities under its rules filed with regulatory authorities, NERC, as the international ERO, has delegated authority to qualified Regional Entities to monitor and enforce compliance with Reliability Standards by users, owners, and operators of the BPS. This delegation is governed by Regional Delegation Agreements (RDA) that have been approved by the appropriate regulatory authorities. NERC and these Regional Entities are responsible for carrying out the CMEP. Each Regional Entity submits its regional CMEP Implementation Plan to NERC for approval based on the requirements of this document.

NERC and the Regional Entities recognize that there are important reliability matters that require prompt communication to industry. NERC has used the Alerts/Advisory[8] process to rapidly inform the industry of such matters. The Implementation Plan strongly encourages the applicable Registered Entities to proactively address such communications as a way of demonstrating good utility practice and a strong culture of compliance and reliability excellence.

[5] Bilateral Electric Reliability Oversight Group, August 3, 2005 (the "Bilateral Principles").
[6] ERO Certification Order at P 3.
[7] *North American Electric Reliability Corporation, Reliability Standards Development and NERC and Regional Entity Enforcement*, "Order on the Electric Reliability Organization's Three-Year Performance Assessment," 132 FERC ¶ 61,217 (2010 at P 1.
[8] *See* Events Analysis: Alerts at http://www.nerc.com/page.php?cid=5|63.

Introduction

The ERO CMEP Implementation Plan is the annual operating plan for compliance monitoring and enforcement activities to ensure that NERC, as the international ERO, and the Regional Entities fulfill their responsibilities under legislation in the United States and other applicable obligations in jurisdictions in Canada and Mexico[9]. Currently, Reliability Standards are mandatory and enforceable in the U.S. and the Canadian provinces of British Columbia[10], Ontario[11], New Brunswick[12], and Saskatchewan[13]. The Canadian province of Alberta[14] has adopted some of the Reliability Standards and is in the process of reviewing others. The legislative framework to make Reliability Standards mandatory and enforceable exists in Manitoba[15], Nova Scotia[16], and Quebec[17]. In Nova Scotia, the Reliability Standards are pending the approval of the Nova Scotia Utility and Review Board. The National Energy Board of Canada[18] is in the process of making Reliability Standards mandatory and enforceable for international power lines.

The compliance monitoring and enforcement activities are carried out by NERC and the eight Regional Entities based on the regulatory authority-approved uniform CMEP[19], the NERC RoP[20], the respective RDA[21] with the eight Regional Entities, and other agreements including Memoranda of Understanding with the Canadian provinces. This plan outlines the implementation requirements to be followed by NERC and the eight Regional Entities. Each Regional Entity submits its 2012 Implementation Plan by November 1, 2011 to NERC. NERC is responsible for approving the Regional Entity Implementation Plans.[22]

The 2012 Implementation Plan includes a set of Reliability Standards that were selected based upon ERO-identified high-risk priorities and a three-tiered approach to compliance auditing. The implementation plan also requires Regional Entities to consider a registered entity's compliance history when determining the scope of compliance monitoring activities. The objectives of the Implementation Plan are to:

- Promote the reliability of the BPS through rigorous compliance monitoring and enforcement activities.

[9] http://www.cre.gob.mx/pagina_a.aspx?id=23
[10] http://www.nerc.com/files/British-Columbia112706.pdf
[11] http://www.nerc.com/files/MOU_between_IESO_NERC_NPCC_02052010.pdf
[12] http://www.nerc.com/files/MOU_NewBrunswick-10032008.pdf
[13] http://www.nerc.com/files/SaskPower_MOU_020309.pdf
[14] http://www.nerc.com/files/NERC-WECC-AESO_MOU_Executed%20Version_071510.pdf
[15] http://www.nerc.com/files/INTERIM_MANITOBA_AGREEMENT.pdf
[16] http://www.nerc.com/files/NSPI_NERC_NPCC_MOU_executed_20100511.pdf
[17] http://www.nerc.com/files/NERC-Regie-NPCC_Agreement_20090508EN_signed.pdf
[18] http://www.nerc.com/files/NEB-NERCMOU091406.pdf
[19] http://www.nerc.com/files/Appendix4C_Uniform_CMEP_20110101.pdf
[20] http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110412.pdf
[21] http://www.nerc.com/page.php?cid=1%7C9%7C119%7C181
[22] *See* Appendix 4C of the NERC RoP at Section 4.2: http://www.nerc.com/page.php?cid=1|8|169

- Facilitate improved consistency of compliance activities throughout North America.
- Monitor all regulatory authority approved Reliability Standards by using the eight CMEP compliance monitoring methods.
- Use risk-based and performance-based criteria for determining the scope for compliance audits.
- Allow flexibility for the ERO and Regional Entities to investigate trends that may pose a near term risk to reliability either across the North American BPS, across an Interconnection or within a Regional Entity boundary.
- Improve the compliance program by analyzing the compliance monitoring experience across North America and implementing necessary improvements.

Risk-Based Compliance Monitoring Approach

The premise of risk-based compliance monitoring is that the amount of scrutiny a registered entity receives in terms of compliance monitoring will be directly commensurate with the risk it poses to the reliability of the BPS. Compliance monitoring encompasses a range of activities, including spot checks, self certifications, audits, and personal correspondence to an entity from the ERO. For entities that do not pose a significant reliability risk, the activities specifically prescribed in this Implementation Plan may suffice. For entities that do pose a significant risk to reliability, it will be necessary for those entities to undergo additional compliance monitoring such as additional focused spot checks, a greater number of self certifications, or broader and deeper audits of greater frequency, etc.

Registered Entities are responsible for compliance with all regulatory approved Reliability Standards and Requirements in effect per their registered function at all times, regardless of what is specified in the AML.

One of the key components to an effective risk-based audit approach is the incorporation of performance-based auditing. Performance audits, according to the United States Government Accountability Office[23], are defined as engagements that provide assurance or conclusions based on an evaluation of sufficient, appropriate evidence against stated criteria, such as specific requirements, measures, or defined business practices. The second component includes a more detailed review and testing of the registered entity's programs and procedures to assure actual performance of the stated programs are being implemented, rather than relying solely on documentation.

To assist the Regional Entities in determining how much risk an entity poses to reliability, a number of aspects have been identified that point to activities, behaviors, and qualities that warrant additional concern prompting an enhanced application of compliance monitoring. Specifically, these aspects include the Technical and Risk Profile of an entity, Reliability Performance Metrics, an entity's Internal Compliance Program, Compliance and Enforcement Metrics and Status, and Regional Entity Qualitative Assessment, which are concepts described in generally accepted government auditing standards (GAGAS)[24]. These five aspects are described below:

- **Technical and Risk Profile:** This profile details the technical components of the Registered Entity. It highlights various aspects of the company's structure and identifies key information that is relative to its risk. Such components include

[23] *See* United States Government Accountability Office – Government Auditing Standards (GAGAS) at Chapter 1: Use and Application of GAGAS at Section 1.25 http://www.gao.gov/new.items/d07731g.pdf.
[24] *See* GAGAS at Chapter 7: Field Work Standards for Performance Audits http://www.gao.gov/new.items/d07731g.pdf

MW capacities, registration information, points of interconnection, and affiliated companies.

- **Reliability Performance Metrics (Trends):** Metrics provide a quantitative approach for measuring a registered entity's performance. Consistent metrics yield a baseline to measure performance as well as compare performance to previous years.
- **Internal Compliance Program:** The strength of a registered entity's internal compliance program evidences its activities to self-monitor reliability and compliance through internal controls, corrective action programs and a culture of compliance. An assessment of a registered entity's internal compliance program includes an evaluation of how the entity addresses the standard FERC 13 questions and the additional FERC 1b compliance criteria, and outlines areas for improvement in the internal compliance program.
- **Compliance and Enforcement Metrics and Status:** These metrics detail the violation history and any open enforcement actions of the registered entity, including consideration of the facts and circumstances surrounding the violations. The evaluation includes consideration of the methods of discovery, with specific focus on repeat violations, the status of any open mitigation plans, and compliance improvements over time.
- **Regional Entity Qualitative Assessment:** This area provides an opportunity for the Regional Entities to include qualitative assessment and regional expertise for what the entity is doing well and areas for improvement.

NERC and the Regional Entities will work together to develop an Entity Risk Profile Assessment template for use across the entire ERO before the end of 2011. When complete, this template will be publically posted on NERC's website for the benefit of both the Regional Entities and registered entities. For registered entities, the template may prove valuable for conducting critical self-assessments in preparation of compliance monitoring actions and other times. Also, the template will be invaluable for the Regions in order to scope audits appropriately.

It must be emphasized that registered entities are responsible for compliance with all regulatory approved Reliability Standards and Requirements in effect per their registered function at all times, regardless of what a registered entity's risk profile may indicate. Regional Entities have the authority and responsibility to expand the scope of an audit, spot check, or any other compliance monitoring process if they consider it necessary when evaluating the compliance of a registered entity.

2012 Implementation Plan Development Methodology

As part of an overall compliance plan, NERC developed the AML of Reliability Standards for 2012 based on the methodology outlined in this section. This framework is a continuation of the initial development process for the 2011 Implementation Plan.

The 2012 Implementation Plan is designed to realize risk-based approaches for ERO programs, priorities and initiatives that meet reliability goals and improve efficiencies. Achieving these goals will be accomplished through the development, maintenance, and implementation of a list of the highest priority Reliability Standards. The Reliability Standards and associated Requirements populating this list will be determined through an annual review of the following:

- ERO High-Risk Priorities
- FERC Orders and Guidance
- Compliance History and Culture
- Input from NERC Staff including Compliance Operations, Critical Infrastructure Protection, Enforcement, Events Analysis and Investigations, Legal, Reliability Assessments and Performance Analysis, and Standards
- Future Considerations

ERO High-Risk Priorities

The purpose of identifying and using a set of priorities is to move away from focusing on processes for "administrative and documentation-related violations that have no effect on bulk power system reliability," as the Edison Electric Institute (EEI) has stated[25]. Instead, the focus is on those Reliability Standards, and more specifically those Requirements within the Reliability Standards, that are most critical to the reliability of the BPS as determined by a set of risk-based criteria. The priorities and correlated Reliability Standards are explained in further detail in *Appendix 1 - 2012 ERO High-Risk Priorities with High Value Associated Reliability Standards*. NERC and the Regional Entities considered these priorities and identified a number of Reliability Standards that apply to each criteria. Many of these Reliability Standards apply to multiple priorities, bolstering their importance and reason for inclusion into the AML.

FERC Order and Guidance

FERC Order No. 729 states that "the Commission hereby adopts the NOPR proposal to direct the ERO to conduct an audit of the various implementation documents developed by transmission service providers to confirm that the complete available transfer capability methodologies reflected therein are sufficiently transparent to allow the Commission and others to replicate and verify those calculations. The Commission clarifies that these audits are not intended to address the competitive effects of these MOD Reliability Standards. Instead, the audit should review each component of

[25] http://www.nerc.com/docs/bot/finance/2010BPB_EEI_Draft2comments.pdf

available transfer or flowgate capability, including the transmission service provider's calculation of capacity benefit margin and transmission reliability margin, for transparency and verifiability to ensure compliance with the MOD Reliability Standards."[26]

The Reliability Standards associated with this order that will be integrated into the 2012 Implementation Plan are MOD-001, MOD-004, and MOD-008.

Violation Trend History

An analysis of the compliance history of Reliability Standards is only one aspect for determining the risk-based compliance approach, and provides insight into which Reliability Standards have proven most challenging for registered entities. Reliability Standards that are understood by registered entities appear to result in more possible violations through the self-report monitoring method. Reliability Standards that are not understood by registered entities, or are complicated, appear to result in more possible violations through the audit and spot check monitoring methods. Through the identification and inclusion of these Reliability Standards in the annual compliance plan, registered entities will have the ability to learn through personal experience, regional workshops, and other outreach programs and resources on how best to improve their compliance programs. Improved compliance programs will result not only in enhanced compliance for these Reliability Standards in particular, but also for all remaining Reliability Standards, through the growth of compliance processes and systems.

A collection of violation statistics results for all Reliability Standards, displayed for all regions as referenced by the ERO and according to each Interconnection, can be seen according to the near term and since June 18, 2007 in Tables 1 and 2 respectively.

Table 1: Top 10 Violation Statistics for the near term in all Regions and by Interconnection for all Reliability Standards.

	Rolling 12 Month (3.28.2010 to 3.28.2011)							
	NERC		Eastern Interconnection		Western Interconnection		ERCOT Interconnection	
	Standard	Violations	Standard	Violations	Standard	Violations	Standard	Violations
1	CIP-007	297	CIP-007	187	CIP-007	84	PRC-005	29
2	PRC-005	199	CIP-004	128	CIP-004	55	CIP-007	26
3	CIP-004	192	PRC-005	121	CIP-006	53	CIP-001	19
4	CIP-006	133	CIP-005	83	PRC-005	49	CIP-004	9
5	CIP-005	131	CIP-006	72	CIP-003	43	CIP-006	8
6	CIP-003	107	CIP-001	62	CIP-005	40	CIP-005	8
7	CIP-002	90	CIP-003	61	CIP-002	36	IRO-001	8
8	CIP-001	89	VAR-002	54	CIP-009	25	VAR-002	7
9	VAR-002	77	CIP-002	52	VAR-002	16	PRC-001	6
10	CIP-009	59	FAC-008	36	CIP-008	9	TPL-002	6

[26] *See Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the Bulk-Power System*, 129 FERC ¶ 61,155 (2009) at P 106.

Table 2: Top 10 Violation Statistics for all time in all Regions and by Interconnection for all Reliability Standards.

	All Time							
	NERC		Eastern Interconnection		Western Interconnection		ERCOT Interconnection	
	Standard	Violations	Standard	Violations	Standard	Violations	Standard	Violations
1	PRC-005	678	PRC-005	425	PRC-005	214	PRC-005	39
2	CIP-001	442	CIP-004	260	CIP-001	184	CIP-001	30
3	CIP-004	390	CIP-007	232	CIP-004	119	CIP-007	26
4	CIP-007	372	CIP-001	228	CIP-007	114	FAC-008	19
5	CIP-006	178	FAC-008	123	TOP-002	80	IRO-001	12
6	FAC-008	171	CIP-006	109	EOP-005	72	CIP-004	11
7	VAR-002	158	CIP-005	103	CIP-003	64	PRC-008	10
8	CIP-005	156	VAR-002	95	CIP-006	61	VAR-002	10
9	CIP-003	152	FAC-009	94	PER-002	55	FAC-009	9
10	CIP-002	135	CIP-002	86	VAR-002	53	CIP-006	8

With the significant presence of FERC Order No. 706[27] (CIP) Reliability Standards among violations, especially in the near term, it becomes difficult to gauge how the FERC Order No. 693[28] Reliability Standards rank in terms of violations. Removing the CIP Reliability Standards from this analysis, the violation statistics for 693 Reliability Standards in the near term and for all time can be seen in Tables 3 and 4 respectively.

Table 3: Top 10 Violation Statistics for the near term in all Regions and by Interconnection for FERC Order No. 693 Reliability Standards.

	Rolling 12 Month (3.28.2010 to 3.28.2011) w/o CIP							
	NERC		Eastern Interconnection		Western Interconnection		ERCOT Interconnection	
	Standard	Violations	Standard	Violations	Standard	Violations	Standard	Violations
1	PRC-005	199	PRC-005	121	PRC-005	49	PRC-005	29
2	VAR-002	77	VAR-002	54	VAR-002	16	IRO-001	8
3	FAC-008	42	FAC-008	36	PRC-008	9	VAR-002	7
4	PRC-008	36	TOP-002	30	BAL-004	5	PRC-001	6
5	FAC-009	32	FAC-009	25	EOP-005	5	TPL-002	6
6	TOP-002	32	PRC-008	23	IRO-STD	4	FAC-009	5
7	COM-002	24	COM-002	20	PER-002	4	TOP-001	5
8	PER-002	21	FAC-001	17	PRC-023	4	PRC-008	4
9	PRC-001	21	PER-002	17	COM-002	3	PRC-004	4
10	FAC-001	20	FAC-003	16	FAC-001	3	FAC-008	4

[27] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008) (Order No. 706).

[28] *Mandatory Reliability Standards for the Bulk-Power System*, 72 FR 16,416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693). NERC realizes each Canadian province has separate Memoranda of Understanding and the use of 693 and 706 in this document for referencing CIP and non-CIP standards.

Table 4: Top 10 Violation Statistics for all time in all Regions and by Interconnection for FERC Order No. 693 Reliability Standards.

	All Time w/o CIP							
	NERC		Eastern Interconnection		Western Interconnection		ERCOT Interconnection	
	Standard	Violations	Standard	Violations	Standard	Violations	Standard	Violations
1	PRC-005	678	PRC-005	425	PRC-005	214	PRC-005	39
2	FAC-008	171	FAC-008	123	TOP-002	80	FAC-008	19
3	VAR-002	158	VAR-002	95	EOP-005	72	IRO-001	12
4	TOP-002	133	FAC-009	94	VAR-002	53	PRC-008	10
5	EOP-005	129	EOP-005	57	EOP-001	50	VAR-002	10
6	FAC-009	127	FAC-003	56	FAC-001	47	FAC-009	9
7	PRC-008	104	FAC-001	53	PRC-008	46	PRC-001	6
8	FAC-001	100	TOP-002	52	VAR-001	44	TOP-001	6
9	PER-002	98	PRC-008	48	TPL-002	35	TPL-002	6
10	EOP-001	84	PER-002	43	COM-001	31	IRO-004	4

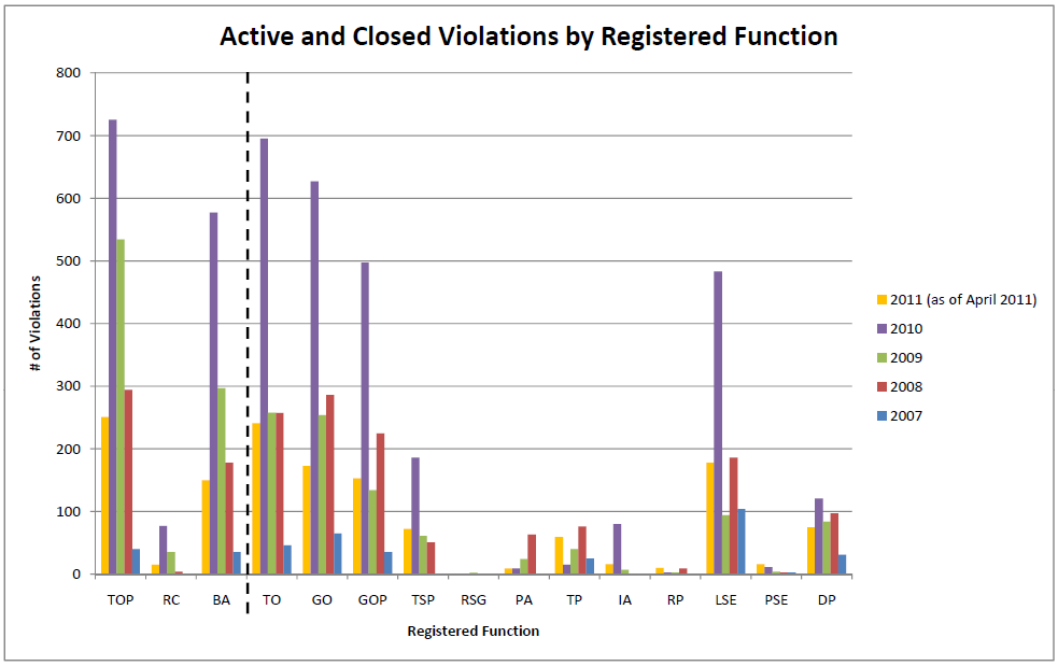


Figure 1: Active and Closed violation summary history per function since 2007.

As a final perspective on violations for recent years, Figure 1 displays the number of active and closed violations attributed to the various registered functions since June 18, 2007. The violations for each function are not necessarily specific or unique violations to each function alone in all cases. Rather, in many cases, a single violation will be applicable to more than one function, resulting in each of the applicable functions reflecting this one violation.

Risk-based compliance includes high-impact violations as well as low-impact violations that are widespread enough to, as an aggregate, represent a high impact to reliability. Thus, violation history is an important tool for assessing which Reliability Standards and, in turn, which functions have proven to be most difficult for compliance and require more attention during audits.

AML and Implementation Plan Input

All eight Regional Entities provided valuable input into the development of the 2012 AML and Implementation Plan. Input was received from members of the ERO Compliance and Enforcement Management Group (ECEMG), the Compliance Monitoring Processes Working Group (CMPWG), and various Regional Entity compliance and enforcement staff.

In addition to the input provided by the Regional Entities, several NERC departments provided insight in terms of the relationship of Reliability Standards to ERO High-Risk Priorities, supplementary information from these groups has been provided in order to help further refine the list of High-Risk Priority Standards. Specifically, the departments that contributed to the 2012 Implementation Plan include Compliance Operations, Critical Infrastructure Protection, Enforcement, Events Analysis and Investigations, Legal, Resource Assessments and Performance Analysis, and Standards.

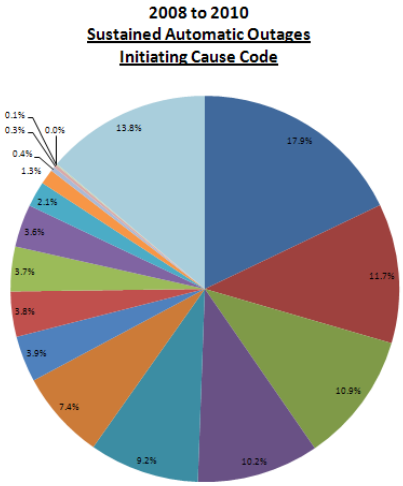
The Reliability Assessment and Performance Analysis department has completed an analysis in which a subset of Requirements with the highest impact to reliability has been identified according to a Standards/Statute Driven Index (SDI), which measures improvement in compliance with Reliability Standards, as part of a Reliability Metrics and Integrated Risk Assessment study[29]. This subset consists of 26 Requirements and is found in Table 5. These Requirements have high Violation Risk Factors (VRFs) and the violations of these Requirements had severe Reliability Impact Statements (RIS), as determined by the Regional Entity.

Table 5: 26 Requirements considered by the Standards/Statute Index as part of Reliability Metrics and Integrated Risk Assessment

Standard	Req.	Standard	Req.	Standard	Req.	Standard	Req.	Standard	Req.
EOP-001-0	R1.	FAC-009-1	R1.	PER-002-0	R3.	PRC-005-1	R2.	TOP-004-2	R1.
EOP-003-1	R7.	IRO-005-2	R17.	PER-002-0	R4.	TOP-001-1	R3.	TOP-004-2	R2.
EOP-005-1	R6.	PER-001-0	R1.	PRC-004-1	R1.	TOP-001-1	R6.	TOP-006-1	R6.
EOP-008-0	R1.	PER-002-0	R1.	PRC-004-1	R2.	TOP-001-1	R7.	TOP-008-1	R2.
FAC-003-1	R1.	PER-002-0	R2.	PRC-005-1	R1.	TOP-002-2	R17.	VAR-001-1	R1.
FAC-003-1	R2.								

The Reliability Assessment and Performance Analysis group has also completed an analysis of the BPS transmission system through the Transmission Availability Data System (TADS). As shown in Figure 2, this analysis points to several causes for sustained outages experienced by North America's transmission system. Keeping these outage causes in mind can be helpful in determining the priority of individual Requirements within already designated, high-risk priority Reliability Standards.

[29] http://www.nerc.com/docs/pc/rmwg/Integrated_Reliability_Index_WhitePaper_DRAFT.pdf



Initiating Cause	Sustained	Percent
Weather, excluding lightning	1379	17.9%
Lightning	902	11.7%
Human Error	842	10.9%
Failed AC Substation Equipment	784	10.2%
Failed AC Circuit Equipment	707	9.2%
Failed Protection System Equipment	572	7.4%
Foreign Interference	299	3.9%
Fire	292	3.8%
Power System Condition	289	3.7%
Other	276	3.6%
Contamination	165	2.1%
Vegetation	97	1.3%
Environmental	28	0.4%
Vandalism, Terrorism, or Malicious Acts	20	0.3%
Unavailable	7	0.1%
Failed AC/DC Terminal Equipment	1	0.0%
Unknown	1064	13.8%
TOTAL	7724	100.0%

Figure 2: Initiating causes of sustained outages for the BPS from 2008 to 2010.

Future Considerations

Future considerations refer to those Reliability Standards that are not yet enforceable, but are implicated by the 2012 ERO high-risk priorities as referenced in Appendix 1. Thus, these suggested Reliability Standards provide guidance on what should immediately be considered for incorporation into the AML following FERC approval and given the current priorities. As indicated by the NERC standards group, the applicable Reliability Standards subject to future enforcement include EOP-005-2, PER-005-1, and PRC-004-2.

Three-Tiered Compliance Approach

Following the compilation of the complete list of highest priority Reliability Standards, the AML, being the minimum scope of compliance audits, will include a subset[30] of Requirements per the FERC-approved RoP. The Requirements identified for the 2012 AML by using a three-tiered approach are described below.

Three-Tiered Approach to Requirements Specification

After selecting a set of Reliability Standards based upon the priorities and criteria identified above, it is necessary to identify the specific Requirements within each of the Reliability Standards that most directly relate to the purpose of the standard itself in terms of its relationship to the identified ERO high-risk priorities and, ultimately, its support for the reliability of the BPS.

In accordance with the FERC-approved Rules of Procedure, the ERO has selected a subset of the Reliability Standards and Requirements to be actively monitored and audited in the ERO annual compliance program for 2012. The three-tiered approach for identifying the Requirements of the Actively Monitored List is described below. For

[30] *See* NERC RoP, Section 401.6.

further information regarding the Implementation Plan methodology, refer to *Appendix 1 – 2012 ERO High-Risk Priorities with High Value Associated Reliability Standards.*

Tier 1 Requirements are those that are the most critical to the purpose and intent of the standard of which they are a part. Additionally, the ability of a registered entity to demonstrate compliance with Tier 1 Requirements will provide guidance to audit teams on the necessity to investigate further and broaden an audit's scope in additional Requirements and/or Reliability Standards.

Tier 2 Requirements are also critical to the purpose of a standard, but less so than Tier 1 in that Tier 2 does not address the ERO high-risk priorities as does Tier 1. Tier 2 also does not pose as severe a risk as Tier 1. This is not to say that compliance with Tier 2 Requirements is not mandatory. Instead, Tier 2 Requirements represent an additional level of inquiry that must be undertaken when a registered entity does not display clear compliance with those most critical Requirements of Tier 1. In the process of this added level of investigation, it may become necessary to branch off into other Reliability Standards that were not identified as relating directly to an ERO priority.

Tier 3 Requirements are those that, while still being significant to BPS reliability, do not represent the purpose of a Reliability Standard directly or are not representative of ERO priorities. The exploration of an audit team into the compliance of a registered entity with Tier 3 Requirements will be initiated through links between identified deficiencies in Tier 1 and 2 Requirements and those of Tier 3.

Regional Entity audit teams are authorized and obligated to expand the scope of a compliance audit to include Tier 2 and Tier 3 Requirements and any other requirements they may deem necessary based on the results of the Registered Entity Profile Assessment or the audit team's collective professional judgment. Audit scope expansion can occur at any point during the process: from the initial review of the Registered Entity Profile Assessment through the close of the audit.

The implementation plan for 2012 will use Tier 1 Requirements as the AML of Reliability Standards. The basis for the requirements of the high-risk priority Reliability Standards in the Tier 1 classification is covered in the following section.

Three-Tiered Approach to Audit Scope Determination

The three-tiered approach is new for 2012. Tier 1 Requirements are identified in the 2012 AML and represent the minimum scope of compliance audits. The potential expansion of an audit into Tier 2 and Tier 3 Requirements will be determined by the Regional Entity based on the results of a risk-based compliance monitoring and entity profile assessment or as determined during the audit process. When a Regional Entity determines that an increased audit scope is necessary based on a risk-based compliance monitoring approach, then the Regional Entity shall notify the registered entity of the increased audit scope. This notification shall include the Reliability Standards and

Requirements that are included in the increased scope, as well as the justification for the increased scope. This notification shall be part of the audit notification package when increased scope is determined early enough in the process. When a Regional Entity determines that an increased audit scope is necessary after the notification package is sent, or while the audit team is on-site, then the Regional Entity shall notify the registered entity of the increased audit scope as soon as possible.

The audit scope for registered entities that are registered to perform identical "functions" will not always be identical across or within the Regional Entities. Registered entities will be advised of the audit scope when they receive the formal audit notice. Compliance information and data archived by the Regional Entity from the implementation of previous monitoring methods will be used in the development of a registered entity's audit scope, including but not limited to previous audits, self certifications, events, and previous or current enforcement actions. Regional Entities will determine the registered entity's specific audit scope based upon the NERC Actively Monitored Reliability Standards List.

Regional Entities are authorized and obligated to implement the annual NERC Implementation Plan. Regional Entity staff may increase the scope of compliance activities related to the NERC program, as described above, but cannot reduce the scope of compliance activities without NERC consent. Where Regional Entities determine that a reduced scope is appropriate, the Regional Entity will submit the *Regional Entity Request to Defer or Reduce the Scope of a Compliance Audit*, which is located in Appendix 3 to the NERC Compliance Operations department at least 90 days prior to the audit for approval.

For Reliability Standards that are incorporated into a compliance audit as the result of a scope expansion, the registered entity that is subject to review of these additional Reliability Standards will not be expected to provide evidence outside of the audit period under review. Registered entities will not be expected to provide evidence outside of the current audit period for the purposes of demonstrating compliance with Reliability Standards unless that evidence is required in accordance with the processes and procedures of the registered entity. For example, a registered entity is expected to provide evidence outside of the current audit period for substantiating long range plans that are longer than an audit period, such as Protection System maintenance and testing intervals. For those Reliability Standards that do not involve long-range plans, an audit team will not be able to request information that is outside of the bounds of the current audit—either three or six years—nor can it identify possible non-compliance outside of this audit period. In other words, the completion of an audit closes one audit period and initiates another, excluding future audit teams from reviewing a registered entity's compliance during past audit periods. This exclusion does not apply to ERO enforcement actions or investigations. Generally speaking, spot checks, data submittals, and self-certifications will not require evidence that precedes the current audit period. This exclusion does not apply to ERO enforcement, investigations, or events analysis. Generally speaking, spot checks, data submittals and self-certifications will not require evidence that precedes the current audit period.

The overall monitoring scope of the 2012 Implementation Plan and AML is based on Reliability Standards that are anticipated to be in effect on January 9, 2012. To the extent new or revised Reliability Standards are adopted, approved by the regulatory authority or in effect during the course of 2012, NERC will work with the Regional Entities to determine whether the 2012 program needs to be amended.

All NERC Reliability Standards identified in the 2012 Implementation Plan are listed in the 2012 CMEP Actively Monitored Reliability Standard list posted on the NERC website at the following link: http://www.nerc.com/commondocs.php?cd=3

The 2012 Actively Monitored Reliability Standards list includes several worksheets. A description of each is listed below:

- **Summary Tabs:** Quick reference listings of the Reliability Standards and Requirements identified for compliance audits, self-certifications and spot checks required by NERC in 2012, and mandatory effective dates for Reliability Standards. These tabs are designed to give the user a quick reference of the Implementation Plan lists. There are also comparisons of the number of Reliability Standards and Requirements monitored in the 2007, 2008, 2009, 2010, and 2011 programs.
- **Requirements Detail Tab:** A detailed list of the Requirements included in the 2012 Implementation Plan.
- **Revision History:** The revision history that will allow users, owners and operators of the BPS to see all of the changes to the 2012 Actively Monitored Reliability Standards spreadsheets.

An analysis of the applicability of Tier 1to the various registered functions is located in Appendix 2. Table 6 highlights some of this analysis and compares the 2012 AML to previous years.

Table 6: Requirements Analysis for the 2012 AML and those going back to 2007

	Requirements Analysis								
Function	Total Applicable Reqs as of 1/9/2012	2012 AML (All Reqs)	2012 AML (CIP only)	2012 AML (693 only)	2011	2010	2009	2008	2007
TOP	498	170	109	61	246	321	134	142	115
RC	398	136	109	27	203	299	97	131	76
BA	408	155	109	46	206	305	107	175	95
TO	368	134	107	27	222	271	70	86	86
GO	302	119	107	12	198	242	34	47	40
GOP	254	121	109	12	168	242	27	38	13
TSP	318	166	107	59	202	206	5	7	2
RSG	20	2	0	2	0	6	6	20	20
PA/PC	178	6	0	6	42	88	56	89	86
TP	143	13	0	13	49	83	51	86	86
IA	184	107	107	0	145	168	0	0	0
RP	22	3	0	3	3	0	0	0	0
LSE	267	123	109	14	157	214	12	26	13
PSE	11	1	0	1	1	3	3	4	3
DP	128	9	0	9	51	54	21	51	51
Avg Reqs	233	84	65	19	126	167	42	60	46

Reliability Standards Subject to 2012 CMEP Implementation

The regulatory authority-approved Reliability Standards and Requirements are monitored through at least one of the CMEP compliance monitoring methods. For the "audit" monitoring method, NERC and the Regional Entities have developed and implemented risk-based and performance-based criteria for determining the scope of the Reliability Standards to be reviewed during the conduct of the audit; risk-based and performance-based audits are discussed in *Chapter 3 - 2012 Implementation Plan Development Methodology*. In addition to these established priorities, other elements considered include FERC Orders and Guidance, compliance history, NERC departmental input, and future considerations utilizing a three-tiered approach. Audit scope is determined by factors that are associated with BPS issues across North America, across the respective Interconnection, and within a Regional Entity boundary, as well as specifics associated with a registered entity.

High-Risk Priority Standards List

Given the considerations of the ERO-identified high-risk priorities, as discussed in Appendix 1, which includes compliance history and violation trend analysis, the number of high priority Reliability Standards is 50, as shown in Table 7. From this group of Reliability Standards, it has been the primary task of Compliance Operations working with input from other groups within NERC to determine and rank the specific Requirements of each standard that best represent the core purpose of that standard to ensure the reliability of the BPS. With the further refined list of Requirements, a subset has been taken as the 2012 AML and will be monitored by the Regions during the year in accordance with the CMEP.

Table 7: High-Risk Priority Reliability Standards

BAL-002	CIP-009	FAC-001	MOD-004	PRC-011
BAL-003	COM-001	FAC-002	MOD-008	PRC-023
CIP-001	COM-002	FAC-003	NUC-001	TOP-001
CIP-002	EOP-001	FAC-008	PER-001	TOP-002
CIP-003	EOP-002	FAC-009	PER-002	TOP-003
CIP-004	EOP-003	IRO-002	PRC-001	TOP-004
CIP-005	EOP-004	IRO-004	PRC-004	TOP-006
CIP-006	EOP-005	IRO-005	PRC-005	TOP-008
CIP-007	EOP-006	IRO-006	PRC-007	TPL-003
CIP-008	EOP-008	MOD-001	PRC-008	TPL-004

High-Risk Priority Standards and Tier 1 Requirements

For each high priority standard identified in Table 7 above, only those Requirements that are recognized as Tier 1 Requirements will become part of the AML of Reliability Standards that must be examined during compliance audits. This section presents a synopsis of the details considered within each group of Reliability Standards to determine the Requirements that meet Tier 1 criteria. Refer to the 2012 AML to view the specific Requirements selected for each of the high-risk priority Reliability Standards.

BAL – Resource and Demand Balancing

BAL-002-0 and BAL-003-0.1b have been identified as high priority Reliability Standards. The performance aspect of BAL-002 is reviewed quarterly through periodic data submittals, but recent winter weather events have shown that contingency reserve is a critical issue, such that special attention should be given here. BAL-003-0.1b has been subject to spot checks in the past, but technical issues discovered through its enforcement have yet to be addressed. Until additional guidance is provided through interpretations, revisions, or otherwise, the Requirements of BAL-003 will be treated as Tier 2 Requirements.

CIP – Critical Infrastructure Protection

CIP-001-2a, CIP-002-3, CIP-003-3, CIP-004-3, CIP-005-3a, CIP-006-3, CIP-007-3, CIP-008-3, and CIP-009-3 have been identified as high priority standards. CIP-001 has an important role as BPS personnel become aware of and properly report sabotage events. Preparedness for reporting, as well as procedures to determine to whom reports should be issued, are critical in mitigating the occurrence of any such event. CIP-002 through CIP-009, or 706 Reliability Standards, are fundamental to the reliability of the BPS in terms of cyber security. Additionally, the CIP Reliability Standards represent eight of the Top 10 Reliability Standards violated over the past year and seven of the Top 10 for all time, indicating that registered entities are having difficulty with compliance issues. Several groups, including NERC, FERC, and the Regional Entities, have provided insight into the various Requirements in greatest support of the purpose of these Reliability Standards.

COM – Communications

COM-001-1.1 and COM-002-2 have been identified as high priority Reliability Standards. COM-001 details and mandates the adequacy of telecommunication facilities, thus supporting nearly every function, and is critical to normal and emergency operations. COM-002 has some similar coverage as COM-001, but goes above and beyond with three-part communication and a methodology for formulating directives. Also, COM-002 is the seventh-most-violated 693 standard for the past year as noted above in Table 3.

EOP – Emergency Preparedness and Operations

EOP-001-0, EOP-002-2.1, EOP-003-1, EOP-004-1, EOP-005-1, EOP-006-1, and EOP-008-0 have been identified as high priority Reliability Standards. EOP-001 is critical in

terms of Energy Emergency Alerts (EEAs), which were important for mitigating impacts from winter weather events taking place during early 2011. EOP-002 complements EOP-001 by assuring the performance of mitigating actions for the both the RC and the BA. EOP-003 designates load-shedding as a suitable action for maintaining the reliability of the BPS, but its action is implied in EOP-001, and therefore the Requirements of EOP-003 are not considered Tier 1 Requirements. EOP-004 is critical in terms of events analysis and helping with the process of mitigating future events, and it is vital that the disturbance reports do not stay within a region, but are shared with NERC for dissemination across North America. EOP-005 sets the foundation for system restoration if actions identified in other EOP Reliability Standards fail and the testing and confirmation of a blackstart capability process is engaged. EOP-006 ensures that the Reliability Coordinator takes the lead role in system restoration initiated through EOP-005, such that coordination in these efforts is not an oversight. EOP-008 accounts for loss of a primary control center and many Requirements not accounted for in any other standard, so this is vital to include.

FAC – Facilities Design, Connections, and Maintenance

FAC-001-0, FAC-002-0, FAC-003-1, FAC-008-1, and FAC-009-1 have been identified as high priority Reliability Standards. FAC-001 designates connections requirements for facilities, which is especially critical in terms of protection and construction of new facilities. With these facilities properly coordinated and accounted for, existing system performance will improve. FAC-002 expands on FAC-001 by requiring that assessments for facilities be undertaken and results coordinated. FAC-003 concerns vegetation management, which is a primary initiator of many events and points to the necessity of an effective vegetation management program. FAC-008 is a documentation-based standard for Facility Ratings Methodology whose execution is accounted for in FAC-009. While both are heavily violated Reliability Standards historically, a review of FAC-009 can lead to the determination of compliance with FAC-008. Additionally, FAC-009 requires coordination of facility ratings, which opens those ratings to peer review as a further check. In that case the Requirements of FAC-008 are not considered Tier 1 Requirements.

IRO – Interconnection Reliability Operations and Coordination

IRO-002-2, IRO-004-2, IRO-005-3a, and IRO-006-5 have been identified as high priority Reliability Standards. IRO-002 determines the sufficiency of tools needed for the RC to perform its role in maintaining the reliability of the BPS, which becomes increasingly imperative when emergency situations arise and Balancing Authorities and Transmission Operators require oversight. IRO-004 covers the planning the Reliability Coordinators must perform and ensures preparations are properly made for seen and unseen emergency events in the operation horizon. IRO-005 contains the only Tier 1 Requirement applicable to the PSE function. It is expected that the Regional Entities will ensure all PSEs are audited according to a six year interval cycle, including those PSEs which were removed from the 2011 audit schedule. For audits of PSEs, Regional Entities will provide a complete audit report regardless of audit scope. IRO-006 discusses the process of transmission load relief (TLR), and while this is an important topic, performance is

covered in IRO-005, and therefore the Requirements of IRO-006 are not considered Tier 1 Requirements.

MOD – Modeling, Data, and Analysis

MOD-001-1a, MOD-004-1, and MOD-008-1 have been identified as high priority Reliability Standards. These three Reliability Standards determine the procedure by which Available Transmission Capability (ATC) is to be calculated by Transmission Service Providers. The proper setting of ATC is vital so facilities are not overloaded, which could lead to possible system emergencies. FERC has mandated that this standard be audited following regulatory approval of the Reliability Standard.

NUC – Nuclear

NUC-001-2 has been identified as a high priority Reliability Standard. The Nuclear Plant Interface Requirements (NIPRs) in NPIR agreements are essential components of NUC-001-2. NERC strongly recommends that generation and transmission entities carefully review their respective obligations under these agreements, including coordinated communication to ensure that parties share a clear and precise understanding of their obligations under these agreements.

PER – Personnel Performance, Training, and Qualifications

PER-001-0.1 and PER-002-0 have been identified as high priority Reliability Standards. PER-001 grants operating personnel the authority to operate the system reliably, but this standard is addressed in many other Reliability Standards with more specific language based upon the function considered, and therefore the Requirements of PER-001 are not considered Tier 1 Requirements. PER-002 encompasses the development of training as well as the training itself of all operating personnel responsible for ensuring reliability of the BPS. Training, especially in preparedness for dealing with or the prevention of emergency events is essential.

PRC – Protection and Control

PRC-001-1, PRC-004-1, PRC-005-1, PRC-007-0, PRC-008-0, PRC-011-0, and PRC-023-1 have been identified as high priority Reliability Standards. PRC-001 promotes understanding of the limitations and performance of protection systems, which is especially important from an operational standpoint such that protection systems are not overloaded and the system cannot be controlled. PRC-004 is a particularly important standard as it applies to misoperations analysis and reporting. As significant protection system misoperations are considered disturbance events, those misoperations for which BPS reliability is affected that are always addressed in PRC-004 are captured by EOP-004 R3 as well, and therefore the Requirements of PRC-004 are not considered Tier 1 Requirements. . Significant misoperations are those that result in such actions as modifications to operating procedures or equipment and identification of lessons learned as identified by Attachment 1 to EOP-004.

PRC-005 is the most violated standard of all time, and its mission to organize and implement protection system maintenance is especially critical for ensuring system reliability. PRC-007 and PRC-008 deal with underfrequency load-shedding (UFLS) while PRC-011-0 involves undervoltage load-shedding (UVLS). Both UFLS and UVLS protection systems are important, but the level of compliance of a Registered Entity with PRC-005 will be most telling for compliance with these Reliability Standards. As a result, the Requirements of PRC-007, PRC-008, and PRC-011 are not considered Tier 1 Requirements. PRC-023, as with all Reliability Standards, has the chief purpose of promoting reliability in the BPS, and in this case it relates to transmission relay protection settings. The concerns surrounding these settings are that they are proper for detecting and protecting against fault conditions. As with UFLS and UVLS maintenance programs, the compliance performance of a registered entity with PRC-005 is a good guide as to how well protection systems at that entity are maintained and tested, which is applicable to PRC-023 as an indicator of the due diligence of an entity in properly setting relays and reviewing transmission system protection schemes. Also, significant misoperations resulting from improper relay settings are addressed through EOP-004, which would allow for a complete review of Requirements in PRC-023 in response to any such event. For those reasons listed, the Requirements of PRC-023 are not considered Tier 1 Requirements.

TOP – Transmission Operations

TOP-001-1, TOP-002-2a, TOP-003-0, TOP-004-2, TOP-006-1, and TOP-008-1 have been identified as high priority Reliability Standards. TOP-001 sets down operation authority for the TOP function, and in so doing, re-iterates language from the EOPs and IROs addressing this same issue. In an event where it can be demonstrated that an operator was not aware of his authority to act, this standard will be important for an entity to be audited on. However, as the authority of system operators is generally well understood, and therefore the Requirements of TOP-001 are not considered Tier 1 Requirements.. TOP-002 deals with normal operations planning, and one of the key concepts to this standard is communications. The outage coordination that is discussed in TOP-003 is implied by TOP-002 in normal operations planning, and therefore the Requirements of TOP-003 are not considered Tier 1 Requirements. . TOP-004 addresses operating in an unknown state and points to insufficient or faulty equipment, processes, planning, etc. and should be considered a high priority issue especially in terms of preparedness for emergencies. TOP-006, the monitoring of reliability parameters, can be gauged from compliance with TOP-008, which complements IRO-005 but this time for the TOP function. The Requirements of TOP-006 will not be considered Tier 1 Requirements while TOP-008 will be.

TPL – Transmission Planning

TPL-003-0a and TPL-004-0 have been identified as high priority Reliability Standards. TPL -003 accounts for the loss of two or more BPS elements, and TPL-004 addresses extreme events, both of which go hand-in-hand with minimizing the impact of emergency events affecting the system. By accounting for N-2 system losses in TPL-003 and losses of several elements in TPL-004, even if projects are not constructed to mitigate all issues

that are identified, acknowledgement of and familiarity with potential events will allow for expedited recovery, should one actually occur.

CMEP Discovery Methods

Compliance Audits

The Reliability Standards selected for compliance audit are determined based on the 2012 Implementation Plan Methodology. The Regional Entities will provide to the registered entity the scope of the compliance audit with the audit notification letter. The scope document will contain the Regional Entities' analysis of their risk and performance-based approach, which determines the audit scope for the registered entity being audited. The intervals for compliance audits is three years for entities registered as a Reliability Coordinator, Balancing Authority, or Transmission Operator, and is six years for entities registered for all other functions[31]. Registered Entities may be audited more frequently as needed based upon the results of risk and performance based assessments performed by the Regional Entities as well as the facts and circumstances surrounding.

Regional Entities have the authority to expand an audit to include other Reliability Standards and Requirements, but cannot reduce the scope without NERC's consent. Regional Entities shall consider past performance, including historical violation trends across the Region and those specific to the registered entity, and changes to compliance responsibility resulting from mergers, acquisitions, corporate re-organizations, open investigations and other factors that in the judgment of the Regional Entity audit staff should be considered as part of the normal planning required for a compliance audit and consistent with generally accepted audit practices.

Regional Entity audit teams are authorized and obligated to expand the scope of a compliance audit to include Tier 2 and Tier 3 Requirements and any other requirements they may deem necessary based on the results of the Registered Entity Profile Assessment or the audit team's collective professional judgment. Audit scope expansion can occur at any point during the process, from the initial review of the Registered Entity Profile Assessment through the close of the audit.

The scope of the registered entities' compliance audits will include a review of all mitigation plans[32] that are open during the on-site audit, as discussed in the CMEP. Regional Entities must provide the compliance audit team with the status, documentation and evidence for all mitigation plans that are to be reviewed.

Should an expanded scope be required based upon significant issues discovered during the on-site portion of the audit process, the audit team will have the discretion to schedule

[31] *See* Rules of Procedure, Section 403.11.1 at http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110412.pdf
[32] *See* Appendix 4C of the NERC RoP at Sections 3.1.4.3 and 6.6: http://www.nerc.com/files/Appendix4C_Uniform_CMEP_20110101.pdf

a follow-up spot check for reviewing the registered entity's compliance with the Reliability Standards and Requirements forming the expanded scope. The audit team will issue a new 30-day notification letter for a spot check in order to allow the registered entity proper time to prepare evidence necessary for the expanded audit scope. The additional compliance monitoring performed by the audit team as a result of the expanded audit scope should not exceed the current audit period.

For compliance audits, NERC provides additional guidance:

Audit Focus or Scope

To increase the efficiency of compliance audits in 2012 the Regional Entity audit teams will have the option of limiting the review of processes and procedures to the Registered Entity's current, in-force documentation, and to the implementation of the Registered Entity's internal compliance program. The audit teams will have the flexibility to review historical information on an as needed basis; this approach allows the audit team to focus on the current reliability risk and determining compliance. In accordance with NERC's RoP[33], documentation submitted to audit teams must be signed, either directly or electronically, by an authorized representative of the registered, regardless of whether or not the document is current or historical. In the event a finding of a possible violation is determined based upon the current, in-force documents, the audit team will review previous versions of the process and procedure documentation to determine the full extent of the possible violation.

In 2012, the audit period, being the range of time for which a registered entity is audited, will be individual to each entity based upon several factors. Depending upon a registered entity's particular situation, the start date for the audit period may be one of several possibilities:

1. the day after the prior audit, or
2. when other monitoring activity by the Compliance Enforcement Authority ended, or
3. the later of June 18, 2007 or the Registered Entity's date of registration if the Registered Entity has not previously been subject to a Compliance Audit.

The end date for the period of time to be covered during compliance audits in 2012 will be the end date for the compliance audits as outlined in the current CMEP, Section 3.1.4.2[34].

It should be noted that, except for those entities that have been recently registered, all Balancing Authorities (BAs), Transmission Operators (TOPs), and Reliability Coordinators (RCs) have experienced at least one compliance audit prior to the end of

[33] *See* Section 3.0 of Appendix 4C of the NERC RoP at: http://www.nerc.com/files/Appendix4C_Uniform_CMEP_20110101.pdf
[34] *See* Appendix 4C of the NERC RoP at http://www.nerc.com/files/Appendix4C_Uniform_CMEP_20110101.pdf

2010. For these Registered Entities that have undergone compliance audits already, all available versions of supporting documentation were reviewed for the entire audit periods, which began on June 18, 2007 and ended at their respective audit completion dates.

CIP Reliability Standards Compliance Audits

Registered entities are subject to audits for compliance with all Requirements of CIP-002-3 through CIP-009-3, which took effect October 1, 2010. If there are indications of possible non-compliance, auditors are authorized and obligated to review an entity's compliance throughout the entire audit period, which includes previous versions of CIP Reliability Standards, in order to determine the extent of possible violations.

If a responsible entity has active Technical Feasibility Exceptions (TFEs), Section 8 of NERC RoP - Appendix 4D[35], Procedure for Requesting and Receiving TFEs to NERC CIP Standards requires that subsequent Compliance Audits of the Responsible Entity conducted prior to the Expiration Date shall include audit of implementation and maintenance of the compensating measures and/or mitigating measures and implementation of steps and conduct of research and analyses towards achieving Strict Compliance with the Applicable Requirement. These topics are to be included in Compliance Audits regardless of whether the audit was otherwise scheduled to include the CIP Standard that includes the Applicable Requirement. Audit Team Leads of CIP audits will have requisite experience, training, and/or credentials in cyber security and/or IT auditing due to the need for subject matter expertise and the complexity of these Reliability Standards.

2012 Compliance Audit Schedule

The 2012 ERO compliance audit schedule, which is a compilation of all regional schedules, will be posted on the Compliance Resource page on the NERC website.[36] This posted schedule is updated at least quarterly, allowing the Registered Entities to have access to the schedule for the upcoming year as soon as possible.

The compliance audits listed on the schedule are labeled as on-site audits or off-site audits. This distinction is only relevant to the location of the audit activities, not the rigor of the audits. Both on-site and off-site audits are compliance audits and are performed using the same Reliability Standards Audit Worksheets (RSAW) and other audit tools and processes. The major difference is that on-site audits would entail physical access to the audited entity's premises. In fact, a large portion of the pre-audit work associated with an on-site audit may actually occur off-site.

Nevertheless, certain types of audits must contain an on-site component because of the nature or functions of the Registered Entity. For example, Reliability Coordinator, Balancing Authority and Transmission Operator functions must be audited on-site. For other BPS users, owners, and operators on the NERC Compliance Registry, the Regions and NERC can use discretion on the location and the conduct of the audit. In either case, the Regional Entity should plan the audit to assure proper scope and rigor.

[35] http://www.nerc.com/files/Appendix4D_TFE_Procedures_20110412.pdf
[36] http://www.nerc.com/commondocs.php?cd=3

As a final note regarding the audits of entities registered for the PSE function, it is expected that the Regional Entities will ensure all PSEs are audited according to a six year interval cycle, including those PSEs which were removed from the 2011 audit schedule.

Compliance Audit Reports

Regional Entities are obligated to provide written audit reports for all compliance audits and spot checks in accordance with *NERC Compliance Process Directive #2010-CAG-001 - Regional Entity Compliance Audit Report Processing*[37]. NERC posts all public versions of the Regional Entities' compliance audit reports of registered entities on the NERC website to satisfy requirements of the CMEP. Regional Entities submit two audit reports for each compliance audit of a Registered Entity: a public report and a non-public report. The public report does not contain critical energy infrastructure information or any other information deemed confidential. The public report does not include a description of how the audit team determined its findings; rather, it includes a listing of the findings. The names of the Regional Entity personnel and registered entity personnel participating in the audit are excluded from the public report, and all participants are identified by title. In accordance with FERC expectations[38], the non-public report shall document all areas of concern related to situations that do not appear to involve a current or ongoing violation of a Reliability Standard requirement, but instead represent an area of concern that could become a violation. The non-public report contains confidential information and detailed evidence that supports the audit findings. The names and titles of all Regional Entity personnel and all registered entity personnel participating in the audit are included in the non-public report.

Public and non-public compliance audit reports that do not contain possible violations are completed by the Regional Entities and are submitted to NERC at the same time. Upon receipt of the reports NERC posts the public reports on its website and submits the non-public audit reports to the applicable regulatory authority.

Public and non-public audit reports that contain possible violations are submitted to NERC at different times. The non-public compliance audit reports are completed by the Regional Entities as soon as practical after the last day of the audit and are then submitted to NERC. Upon receipt of the non-public reports, NERC submits them to the Applicable Governmental Authority. The public reports that contain possible violations are completed by redacting all confidential information in the non-public reports. The Regional Entities retain the public version of compliance audit reports that contains possible violations until all violations are processed through the NERC CMEP. Due process is considered complete when all possible violations are dismissed or when a violation is confirmed or a settlement is reached and a decision has been rendered, if applicable, by the regulatory authority (e.g. Notice of Penalty (NOP) has been issued in

[37] http://www.nerc.com/page.php?cid=3|22

[38] *Compliance with Mandatory Reliability Standards*¸ "Guidance Order on Compliance Audits Conducted by the Electric Reliability Organization and Regional Entities," 126 FERC ¶ 61,038 (2009) at P13, http://www.nerc.com/files/GuidanceOrderOnComplianceAudits-01152009.pdf

the United States). Upon completion of due process, the Regional Entities submit the public version of the compliance audit reports to the registered entities for review and comment prior to submitting them to NERC. Upon receipt of the public reports NERC posts them on the NERC website[39].

In order to promote transparency and to provide the industry with guidance for improving compliance, NERC will be publishing a document containing the areas of concern, lessons learned, recommendations, and suggestions developed by ERO audit teams as part of the compliance monitoring process for 2011. This document will be similar to the Case Notes[40] that NERC currently provides in regard to the lessons learned as a result of registered entities completing their mitigation plans. The document will not mention or make reference to any registered entities specifically, but will instead focus on those various aspects for supporting and helping to enhance compliance programs.

Compliance Tools

The RSAWs are designed to add clarity and consistency to the assessment of compliance with Reliability Standards. The RSAWs are used for multiple compliance monitoring methods. Comments on these and any of the ERO's auditor resources are welcome and can be directed to the Regional Entity Compliance Managers[41].

The RSAWs are posted on the NERC public website[42] and provide information to the industry about expectations of the ERO compliance auditors when evaluating compliance with a Reliability Standard. NERC works in close coordination with the Regional Entities to ensure the information in existing RSAWs is updated with the latest regulatory authority language and guidance, and new RSAWs are developed as Reliability Standards are approved. It is recommended that Regional Entities and registered entities check the NERC website regularly to ensure the latest available versions of RSAWs are being used.

NERC works with Regional Entities to review these RSAWs on a continual basis for improvement. NERC plans to migrate RSAWs to a database format in the future to support timely updates as Reliability Standards are approved, modified, or retired.

Mitigation Plans

Registered Entities must be in compliance with all Reliability Standards at all times. NERC and the Regional Entities encourage aggressive self-assessments and analysis and self reporting of noncompliance by registered entities. Registered entities are further encouraged to draft mitigation plans upon identification and self reporting of possible violations, prior to the required submission timeline per the CMEP. Mitigation plans are not an admission of a violation and are treated as voluntary corrective action. However, mitigation plans duly prepared and promptly submitted to the Regional Entity will be

[39] Public audit reports can be found at: http://www.nerc.com/page.php?cid=3|26|246
[40] http://www.nerc.com/page.php?cid=3|22|371
[41] Information concerning Regional Entity programs is available at: http://www.nerc.com/page.php?cid=3|23
[42] http://www.nerc.com/page.php?cid=3|22

used to demonstrate a positive, proactive culture of compliance in any potential enforcement action.

Self-Certification

All registered entities are required to participate in the annual self-certification each year per the NERC Actively Monitored Reliability Standard list. Regional Entities, at their discretion, may include additional Reliability Standards to include in the Regional 2012 Implementation Plan. Registered entities will receive guidance and instruction from their respective Regional Entity concerning self-certification submittals. Self-certification is an important component of the ERO Compliance Monitoring and Enforcement Program. It is one of the discovery methods that monitor a Registered Entity's compliance with Reliability Standards, especially those that have not been included in audit scopes in recent years. Self-certification waivers are not available as all applicable Reliability Standards must be self-certified.

CIP-002-3 through CIP-009-3 Reliability Standards

Registered entities are required to self-certify once per year, as scheduled by the Regional Entity and according to the Regional Entity's 2012 Implementation Plan. However, self-certification may expand to include CIP supplemental questionnaires as directed by NERC or an Applicable Governmental Authority. For further information, refer to Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities[43].

A unique characteristic of the CIP Standards pertains to self-certification: CIP-002-3 R4 requires all entities to annually approve their risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets, even if such lists are null. Thus, entities will need to submit self-certification for CIP-002-3 even if they conclude they have no Critical Assets.

The requirements for Self-Certification differ from the reporting requirements for approved TFEs. TFE reporting requirements for Responsible Entities are described in Section 6 of NERC RoP - Appendix 4D, Procedure for Requesting and Receiving TFEs to NERC CIP Standards.

Spot Checks

Spot checks are compliance audits with a much narrower focus, but are performed with the same rigor as a compliance audit. NERC and the Regional Entities have the authority to conduct spot checks of any regulatory approved Reliability Standards. Regional Entities may expand the list of Reliability Standards and Requirements they have scheduled for spot checks in their Regional Implementation Plan. Regional Entities shall ensure, however, that they satisfy all spot check requirements in the NERC Reliability Standards, RoP, and CMEP. Regional Entities are obligated to provide written audit reports for all compliance audits and spot checks in accordance with *NERC Compliance*

[43] http://www.nerc.com/docs/standards/sar/Imp-Plan_Newly_Identified_CCA_RE_clean_last_approval_2009Nov19.pdf.

Process Directive #2010-CAG-001 - Regional Entity Compliance Audit Report Processing[44]. The standard audit report template and procedure provided in NERC Compliance Process Directive #2010-CAG-001 will be used for all spot check reports.

CIP Reliability Standards

Selected Reliability Standards Requirements of CIP-002-3 through CIP-009-3 will be audited and additional spot checks may be performed at the Regional Entity's discretion. CIP audits, including CIP spot checks, will require the appropriate reports per the RoP, CMEP, and *NERC Compliance Process Directive #2010-CAG-001 - Regional Entity Compliance Audit Report Processing*[45].

Periodic Data Submittals

Specific Reliability Standards and Requirements have been identified for periodic data submittals. The periodic data submittals for 2012 are as shown on the Requirements Tab of the 2012 Actively Monitored Reliability Standards list. Specific information regarding periodic data submittals is defined in the Regional Entity Implementation Plans.

Self-Reporting

Registered Entities are encouraged to self-report compliance violations with any regulatory authority-approved Reliability Standard. In most cases, self-reports of compliance violations are provided to the appropriate Regional Entity.[46] The ERO strongly encourages Registered Entities to report violations of Reliability Standards as soon as possible to ensure that the entity receives any potential cooperation credits[47] for self-reporting[48] and minimizing any ongoing risk to the BPS.

Exception-Reporting

Specific Reliability Standards and Requirements in the 2012 Actively Monitored Reliability Standards list have been identified for exception reporting. The Registered Entities are expected to report to the Regional Entities for all events or conditions occurring that are exceptions to the associated Reliability Standard Requirement.

Reporting Credit

Currently, self-reporting credits will not be given to those registered entities for filing reports they are required to make[49]. Additionally, there are no reporting credits available during the enforcement process for mandatory reporting of self-certifications and self-

[44] http://www.nerc.com/page.php?cid=3|22
[45] http://www.nerc.com/page.php?cid=3|22
[46] The exception would be where the self-reporting entity is itself a Regional Entity, in which case the self-report should go directly to NERC in accordance with the Regional Entity's delegation agreement and other agreements with NERC.
[47] *North American Electric Reliability Corporation*, "Order on Review of Notice of Penalty," 134 FERC ¶ 61,209 (2011) at P 13, http://www.ferc.gov/whats-new/comm-meet/2011/031711/E-3.pdf
[48] *Guidance o Filing Reliability Notices of Penalty, North American Electric Reliability Corporation*, "Order on Review of Notice of Penalty," 124 FERC ¶ 61,015 (2008) at P 32, http://www.ferc.gov/EventCalendar/Files/20080703131349-AD08-10-000.pdf
[49] *North American Electric Reliability Corporation*, "Order on Review of Notice of Penalty," 134 FERC ¶ 61,209 (2011) at P 47, http://www.ferc.gov/whats-new/comm-meet/2011/031711/E-3.pdf

reports during or after an audit. Cooperation credits may be available to a registered entity during the enforcement process based on facts and circumstances.

NERC has requested a rehearing on the issue of self-reporting credits from FERC[50]. NERC recognizes that self-reporting credit is a critical component to entity compliance and BPS reliability and encourages registered entities to continue to self-report all possible violations as soon as possible.

Complaint

All regulatory authority-approved Reliability Standards or Requirements can be the subject of a complaint regarding a compliance violation by a Registered Entity. Complaints, if validated, can initiate one of the other compliance monitoring methods in order to determine the full extent of potential non-compliance.

NERC maintains a Compliance Hotline that is administered by the Event Analysis & Investigation (EA&I) group. Any person may submit a complaint to report a possible violation of a Reliability Standard by calling 404-446-2575, sending an e-mail directly to hotline@nerc.net or completing the form on https://www.nerc.net/hotline/. Unless specifically authorized by the complainant, NERC and Regional Entity staff will withhold the name of the complainant in any communications with the violating entity. All information provided will be held as confidential in accordance with the NERC Rules of Procedure. EA&I will informally seek additional information regarding the potential violation of Reliability Standards from the submitter and others, as appropriate. EA&I may refer the matter for further investigation by NERC or the appropriate Regional Entity.

Note: The NERC Compliance Hotline is for reporting complaints or possible compliance violations of Reliability Standards by an entity. For other questions regarding the NERC CMEP or Reliability Standards, please send an email to compliancefeedback@nerc.net.

Compliance Investigations

A Compliance Investigation may be initiated at any time by the NERC or the Regions in response to a system disturbance, Complaint, or the possible violation of a Reliability Standard identified by any other means. Compliance Investigations are confidential, unless FERC directs otherwise and are generally led by the Regional Entity's staff. NERC reserves the right to assume the leadership of a Compliance Investigation.

The Compliance Enforcement Authority reviews information to determine compliance with the Reliability Standards. The Compliance Enforcement Authority may request additional data and/or information as necessary through formal Requests for Information, site visits, sworn statements, etc. to perform its assessment.

[50] http://www.nerc.com/files/FinalFiled_Req_For_Clarification_Turlock_Order_20100418.pdf

ERO Compliance Monitoring and Enforcement Program Organization

The focus of the ERO Enterprise's compliance program is to improve the reliability of the BPS in North America by fairly and consistently enforcing compliance with regulatory approved Reliability Standards. Specifically, the program is designed to ensure that the right practices are in place so that the likelihood and severity of future system disturbances are substantially reduced, while recognizing that no Reliability Standards or enforcement process can fully prevent all such disturbances from occurring. In order to fulfill these responsibilities the NERC compliance organization is comprised of four primary groups: Compliance Operations, Compliance Enforcement, Event Analysis and Investigation, and Regional Entities.

- The overriding goal of the Compliance Operations Department is ensuring success of the Regional Entities and registered entities with respect to reliability compliance.

- The Compliance Enforcement Department is tasked with ensuring strong, consistent, and expeditious enforcement of Reliability Standard violations.

- The Event Analysis and Investigation Department combines the technical expertise of NERC's situation awareness staff, events analysis staff and its event investigators to facilitate efficient processing of these complementary activities to provide lessons learned, which will promote increased reliability of the BPS.

- The Regional Entities execute the CMEP on behalf of the ERO according to their respective Regional Delegation Agreements.

In addition to the ERO's responsibilities, the CMEP (RoP Appendix 4C) states that all entities that are registered in the NERC Compliance Registry have the obligation to comply with all enforceable Reliability Standards for the functions for which the entity is registered. All registered entities are subject to the compliance monitoring methods included in the CMEP, and should be aware of their obligations. Every registered entity should have an aggressive internal compliance program for identifying and performing its CMEP responsibilities. Also, the registered entities are encouraged to participate in the Reliability Standards development process, recognizing that the Reliability Standards serve as the basis for compliance.

Compliance Enforcement

Program Scope and Functional Description

NERC's Compliance Enforcement department conducts all of NERC's enforcement activities, including:

- Docketing of all possible violations coming into the NERC enforcement program,
- Prosecution of compliance violation matters arising out of NERC-led investigations and audits,
- Review of all mitigation plans and dismissals approved by Regional Entities,
- Processing of all compliance violations prosecuted by Regional Entities, and
- Analysis of compliance statistics.

2012 Goals and Deliverables

A priority for this department is to achieve greater efficiencies in enforcement processing by focusing both NERC and Regional Entity compliance enforcement resources on the cases that have the most significant impact on the reliability of the BPS. This should reduce the overall ERO compliance caseload by ensuring that the number of cases processed through the filing of a notice of penalty exceeds the number of cases coming into the ERO docket and should thus allow NERC to close out cases expeditiously to provide timely lessons learned to the industry. NERC's Compliance Enforcement staff has realized significant efficiencies and expects to gain efficiencies through better utilization of existing resources in the future.[51]

Despite efforts to attain greater efficiencies, a significant gap is anticipated in the number of cases coming into the enforcement process and the number of cases the enforcement team can close out on a monthly basis. In the past year, as reflected in Figure 3, the ERO's caseload of active violations expanded from 2006 in January 2010 to 3193 in

[51] There is substantial evidence of this increased efficiency. In 2010, Compliance Enforcement rolled out new risk-based processes in early 2010. These processes, including the introduction of the Disposition Document, Abbreviated Notice of Penalties, and other process improvements, have helped streamline compliance enforcement. Over the course of the year, Compliance Enforcement has also increased collaboration with Regional Entities and increased the number and expertise of Enforcement Staff. As a consequence, Compliance Enforcement has increased by 3.5 times the number of violations processed each month in 2010 compared to the number of violations processed each month in 2009 (70/month vs. 20/month).

An administrative citation process was initiated in January 2011 that will enable NERC and the Regional Entities to address new violations by submitting a single streamlined NOP covering numerous lower risk violations. See North American Electric Reliability Corporation, 134 "Notice of No Further Review of Initial Administrative Citation Notice of Penalty," 134 FERC ¶ 61,157 (2011) ("March 3, 2011 Order").

As of September 30, 2011, the compliance enforcement initiative will introduce a new enforcement process that will retire the administrative citation process. This is described in further detail below, in the 'Key CMEP Activities and Initiatives' section of the implementation plan.

January 2011. The rate of new violations coming into the case load has increased dramatically from an average of 140 violations per month in early 2010 to an average of 203 violations per month at the start of 2011. The increase in caseload is primarily attributable to the large number of violations of CIP Standards that have been and will be entering the system. As reflected in Figure 4, the number of incoming violations each month from non-CIP Reliability Standards has been relatively stable since June 2008, but with the staged implementation of the CIP Reliability Standards, the number of incoming violations each month from CIP Reliability Standards continues to rise.

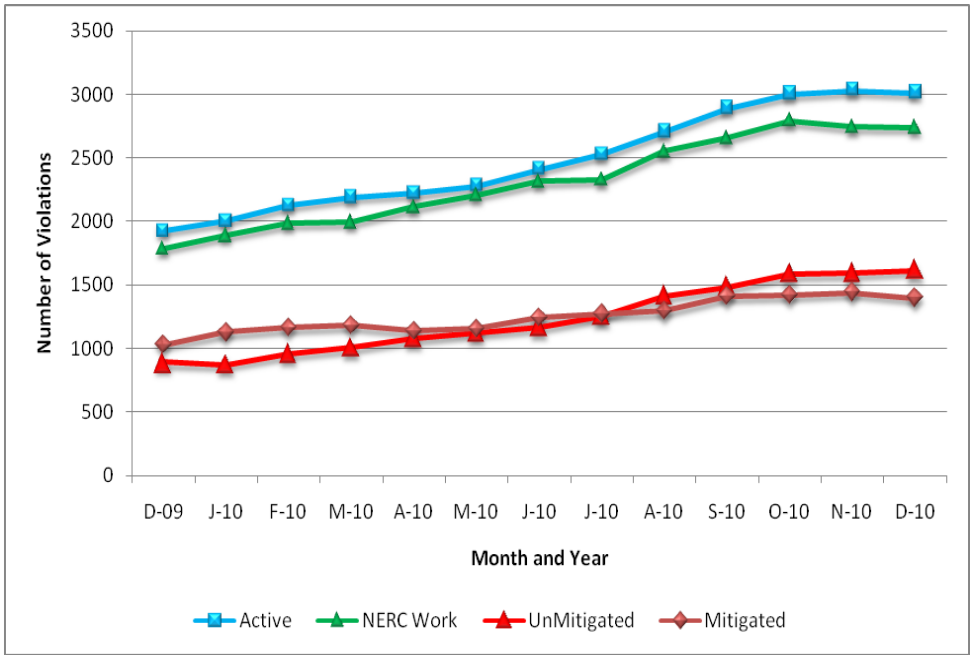


Figure 3: Compliance Processing Statistics for Calendar Year 2010.

The influx of new violations is expected to outstrip the number of violations NERC can process each month. Compliance Enforcement processed to BOTCC approval an average of 70 violations per month in 2010. With the implementation of streamlined procedures and the advent of the administrative citation process, the team has processed an average of 130 violations per month for the first three months of 2011. Still, further streamlining is required to reduce the overall caseload. NERC staff is actively working with Regional Entities and registered entities to develop further ways in which to streamline the enforcement process and ensure that enforcement resources are efficiently deployed to address the most significant risks to bulk power system reliability.

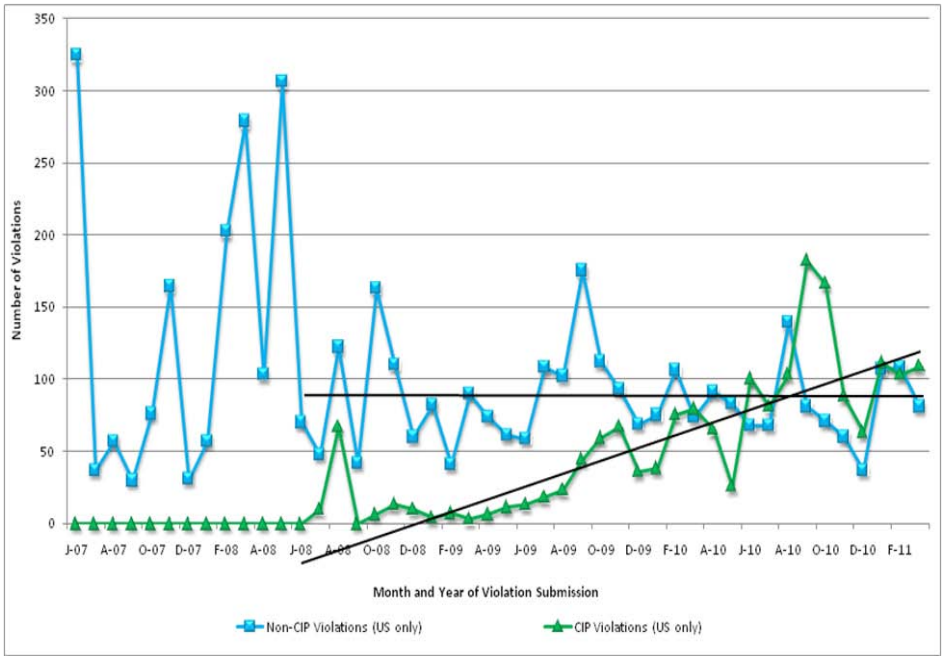


Figure 4: Violations Submitted per Month (CIP vs. Non-CIP).

Beyond management of the caseload, another significant area of focus for the next year will be to improve the submittal and completion of mitigation plans. As reflected in Figure 1 above, the increase in active violations in 2010 brought with it an increase in the number of unmitigated violations and a decline in the overall percentage of active violations subject to a mitigation plan. Currently, less than half of the active violations in the caseload have been mitigated, and a number of violations dating back to 2007 are not yet covered by mitigation plans. To help manage risk to the BPS, Compliance Enforcement will focus on understanding and improving upon the mitigation process.

Key CMEP Activities and Initiatives

NERC and the Regional Entities receive CMEP implementation feedback from the Members Representative Committee (MRC), Compliance and Certification Committee (CCC) and other stakeholders through the use of audited entity feedback forms. All feedback and input from these groups, among others, are reviewed on a continual basis for opportunities for improvement. NERC and the Regional Entities are committed to continuous improvement of the CMEP implementation.

CMEP Transparency Elements

NERC and the Regional Entities continuously balance the request from the industry to improve transparency with the confidential nature of the CMEP processes. Figure 5 is a pictorial view of the compliance process, and it shows how most of the processes in the CMEP fall under a window of confidentiality. NERC and the Regional Entities are continuously identifying and implementing innovative ways to share CMEP process information while honoring confidentiality. Additional initiatives are underway to increase transparency of CMEP elements in 2011. They are discussed later in this Chapter.

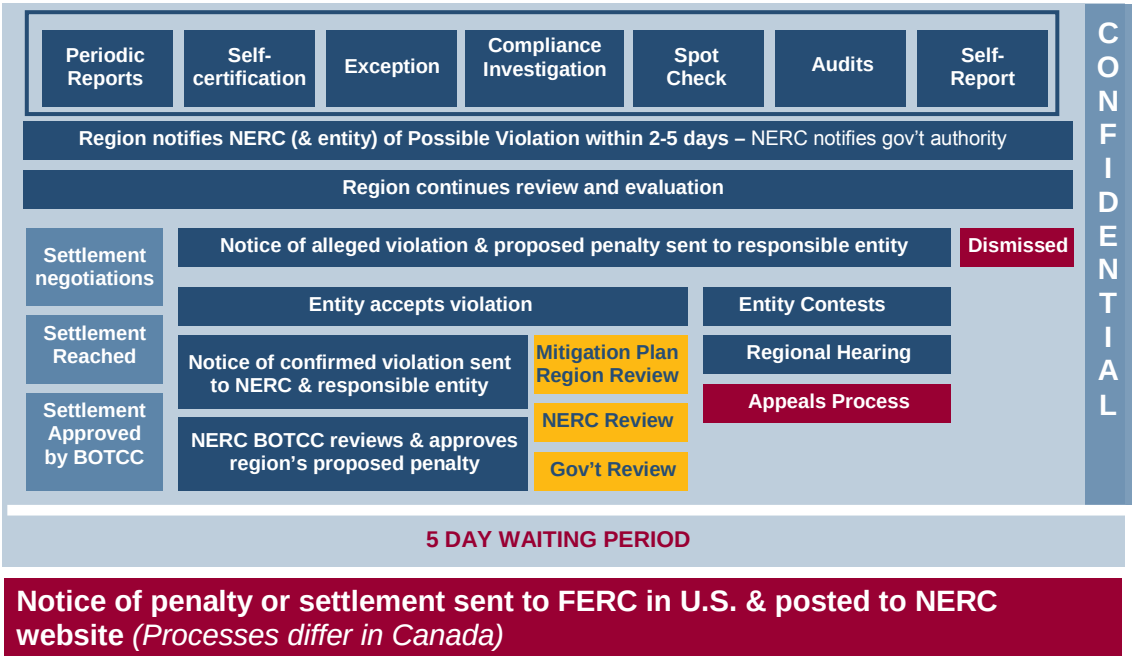


Figure 5: Compliance Process

In 2010, NERC began publicly posting CMEP implementation and process information. NERC Compliance Operations will continue to review and publicly post CMEP implementation and process information in the form of public notices[52] in order to increase transparency of the CMEP application to registered entities.

[52] Public notices are available at: http://www.nerc.com/page.php?cid=3|22

Compliance Operations and REs Communications

Seminars and Workshops

Seminars and workshops for compliance activities are conducted at both the Regional Entity and NERC levels. Each Regional Entity provides Compliance Workshops at least once a year. NERC offers four workshops per year for registered entities. Two of these workshops focus on "Standards and Compliance," and two of these workshops focus on assisting registered entities in improving their compliance programs. The seminars and workshops are important learning exercises for those subject to Reliability Standards. NERC and the Regional Entities will continue compliance seminars, workshops and panel discussions to educate registered entities and to increase transparency of CMEP processes that are important to reliability.

Transparency Communications

The NERC Compliance Operations Program and the Regional Entities are working toward common goals related to improving consistency, increasing transparency, and creating more efficiency in compliance processes. Past field experience gained by Regional Entities and NERC is an important part of meeting the goal to provide clarity on particular items and state the proper expectations. NERC provides transparency information in various formats, depending on the scope of the matter and relevance to the particular functions within the BPS. These include the following, as well as other means as NERC deems necessary:

CANs – Compliance Application Notices[53]

CANs focus on current and future auditable compliance applications. CANs provide continued compliance and enforcement guidance as a means to facilitate information to industry while Reliability Standards are revised and improved as discussed in FERC Order No. 693.

CARs – Compliance Analysis Reports[54]

CARS are a historical look at compliance trends for individual Reliability Standards and will include addendums when the information is updated.

Case Notes[55]

Case Notes provide examples of mitigation plans for recent possible violations that have not completed processing through an enforcement action. Case notes do not identify the Registered Entity.

Bulletins[56]

Bulletins provide general information or clarification on current and future issues.

[53] http://www.nerc.com/page.php?cid=3|22|354
[54] http://www.nerc.com/page.php?cid=3|329
[55] http://www.nerc.com/page.php?cid=3|22|371
[56] http://www.nerc.com/page.php?cid=3|22

Directives[57]

Directives provide notice of a mandatory action and guidance for Regional Entities.

Lessons Learned[58]

Lessons Learned result from an event analysis. They provide examples of how a problem occurred and was identified, and the corrective action taken.

Annual CMEP Reports[59]

Annual CMEP Reports are assessment of the previous year's CMEP and are used in the planning and development of future years' annual CMEP Implementation Plans.

Compliance Application Notices

CANs provide necessary compliance guidance and fulfill NERC's obligations under FERC Order No. 693 to provide compliance guidance going forward.

In FERC Order No. 693[60] several commenter's argued there were gaps and ambiguities in the standards and requested relief from monetary penalties and even compliance with the Reliability Standards. According to paragraph 274 FERC opined, "As discussed in our standard-by-standard review, each Reliability Standard that we approve contains Requirements that are sufficiently clear as to be enforceable and do not create due process concerns."

Further, in Order No. 693 paragraph 277, the Commission agreed with NERC that, even if some clarification of a particular Reliability Standard would be desirable at the outset, making it mandatory allows the ERO and the Regional Entities to provide that clarification on a going-forward basis while still requiring compliance with Reliability Standards.[61]

Thus, the Compliance Application Notice (CAN) serves two purposes:

1. To provide *transparency to industry* on how an ERO compliance enforcement authority will apply compliance criteria to determine possible non-compliance with a NERC Reliability Standard; and
2. To *establish consistency in the application of compliance criteria* across all compliance enforcement authorities.

In practice, auditors must make in-the-field determinations of what constitutes possible non-compliance of a Reliability Standard. In essence, the auditor, without guidance,

[57] http://www.nerc.com/page.php?cid=3|22
[58] http://www.nerc.com/page.php?cid=5|385
[59] http://www.nerc.com/page.php?cid=3|26
[60] FERC Order No. 693, Docket No. RM06-16-000 (March 16, 2007).
[61] "NERC can maximize consistency and appropriateness of treatment in compliance matters most efficiently if it has the ability to advise or provide direction…at an early stage…," FERC Order on NERC Three Year Assessment, Docket Nos. RR09-7-000 and AD10-14-000, §216.

must make an interpretation of the standard. A CAN attempts to gather the practices that occur in the field, and, if the practices are consistent, provide transparency of the compliance application to industry. In the event that auditor practices vary, the posted CAN establishes a consistent compliance application that all auditors will adopt going forward. The implementation of this type of compliance application may create some change as it drives consistency across the ERO.

A CAN provides significant advantages to industry. Registered Entities will have visibility into how compliance will be applied and will be able to depend upon the compliance application being consistent across auditors and regions. In the event that an inconsistency occurs, a registered entity will be able to point to the CAN as the auditable compliance application. Additionally, CANs can be generated in a relatively short period – approximately three months – compared to the codified Standards Development Process,[62] which may take longer than a year.

CANs are posted for a three-week industry comment period. All comments that are received for each CAN are carefully reviewed and considered. Industry comments are especially important when the compliance application varies across auditors or regions, as the CAN will establish a consistent application.

NERC's belief is that transparent, open communication is beneficial, and transparency of compliance applications provides an opportunity to formally address areas of concern. When industry disagrees with the compliance application identified in a CAN, there are existing processes that continue to be available for formal resolution. A registered entity may:

1. request a formal interpretation;[63] or
2. submit a Standard Authorization Request (SAR) to modify the standard; or
3. if a registered entity is found to have a non-compliance based on the compliance application identified in a CAN, to contest the violation; or
4. submit a technical rationale why the compliance application is incorrect or should be modified.

The compliance application identified in a CAN will be retired when a future standard or interpretation that addresses the issue – either by supporting the CAN or changing it – has been approved by FERC and is enforceable. Further, a CAN may be revoked or revised if additional information is brought forward to demonstrate that the CAN is incorrect.

As of June 29, 2011, there are 16 CANs posted as final on the NERC website and 26 additional CANs in various stages of the development process, plus over 20 CAN requests pending development.

[62] See the NERC Rules of Procedure, Appendix 3A, Standards Process Manual, Effective September 3, 2010.

[63] An interpretation is conducted through the Standards Development Process. As such, it is formally filed with FERC and will result in an order issued by FERC Commissioners.

Compliance Analysis Reports

Registered entities can use Compliance Analysis Reports (CAR) and any corresponding addendums to view historical information on highly violated Reliability Standards and those most critical to reliability. For those Requirements in each standard that have similar violation descriptions for multiple registered entities, NERC and the Regional Entities provide suggestions for registered entities to improve their programs to comply with the Requirements. The registered entities can also see the discovery method of each of the violations. If the registered entities have a high percentage of violations discovered through self-reports or self-certifications, it shows an aggressive ICP. If the standard has a high percentage of violations discovered through compliance audits, there should be some concern that the registered entities are uncertain how to comply. The report serves as a mechanism to deliver some clarity and information to improve compliance.

Regional Entities can use the reports to point out any regional issues that may have resulted from the violations that could involve compliance, registration, or enforcement issues. They can also use the violation descriptions to improve consistency on auditing to the standard.

Training

Compliance Auditors

The NERC compliance auditor training is based in part on generally accepted auditing practices found in documents such as the Government Accounting Office (GAO) Generally Accepted Government Auditing Standards, and is revised from time to time. Continuing education will provide training on specific auditing issues to promote consistency and increased reliability.

In 2012, NERC Compliance Operations will design and develop a tiered system of qualifications for compliance staff with requisite testing and/or credentials. Training is an important part of delivering consistency across NERC and the Regions.

In addition, NERC sponsors seminars on specific matters as a way to provide continuous education to ERO staff. Two such seminars were performed in 2011, and two are scheduled for 2012.

Specialized training for CIP auditors was performed in 2011 and will continue in 2012. It is intended not only to address technical issues unique to the CIP Standards environment, but also to increase the skills of CIP auditor staff. Two sessions of CIP Standards Training (CIP Basics for Auditors) are scheduled for 2012. NERC encourages the CIP audit staff to have requisite experience, training and credentials in cyber security and IT auditing.

Compliance Investigative (CI) Staff

A “Fundamentals of CI” course/seminar has been conducted for NERC and Regional Entity staff by NERC over the last two years. The training is scheduled to be conducted twice annually and is revised from time to time.

Mitigation Plans

Non-Confirmed Violations Without Submitted Mitigation Plans

In 2010, Compliance Enforcement staff began analyzing various violation processing trends for the Board of Trustees Compliance Committee and for stakeholders. A trend has been identified in an increasing number of active violations in NERC's violation processing database for which the registered entities have not yet submitted mitigation plans. While there are a number of different reasons for the increase, NERC would like to remind registered entities of the importance of timely mitigation plans and that the submission of a mitigation plan is not an admission of a confirmed violation. Voluntary correction of possible violations in a timely manner may also reduce the potential of a penalty consistent with section 4.3.3 of NERC's Sanctions Guidelines[64].

Compliance Enforcement staff will continue to clarify that the submission of a mitigation plan is not an admission of confirmed violation. Prior to, and if, enforcement confirms a possible violation to an alleged violation, the mitigation plan is treated as a voluntary corrective action. The evidence collected by ERO enforcement will determine whether a violation exists.

Registration and Certification

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the regulatory approved Reliability Standards and is described in the NERC Rules of Procedure Appendix 5A Organization Registration and Certification Manual. As described in the NERC Statement of Compliance Registry Criteria, NERC will include in its compliance registry each entity that the ERO concludes can materially impact the reliability of the BPS. NERC is obligated to identify all organizations to be listed in the NERC compliance registry. Identifying these organizations is necessary and prudent for the purpose of determining resource needs both at the NERC and Regional Entity level, and to begin the process of communication with these entities regarding their potential responsibilities and obligations.

Multi-Regional Registered Entities (MRRE)

There are several activities related to registration, compliance monitoring and enforcement involving registered entities that are registered and operate and/or conduct business in multiple regions. NERC and the Regional Entities have worked together to develop a process for MRREs that will delineate the CMEP implementation for these types of registrations. The purpose of the Multi-Regional Registered Entity (MRRE) process is to describe the coordinated CMEP processes that will be used by NERC and the Regional Entities for a subset of registered entities that are registered in multiple regions on a voluntary basis. The MRRE process allows these entities the ability to request to be accountable to one Compliance Enforcement Authority (CEA). This

[64] See Appendix 4B *Sanction Guidelines of the North American Electric Reliability Corporation* from NERC's Rules of Procedure at:
http://www.nerc.com/files/Appendix4B_Sanction_Guidelines_20110101.pdf

coordinated process provides for increased efficiencies in compliance resource allocation for NERC, the Regional Entities, and the registered entities while maintaining the reliability of the BPS. Due to potential Regional Entity jurisdictional issues, the MRRE process is on hold as of May 2011 pending NERC legal's review and determination of these issues.

Joint Registration Organization and Coordinated Functional Registration

Joint Registration Organization (JRO)[65]: In addition to registering as the entity responsible for all functions that it performs itself, an entity may register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register, and, thereby, accept on behalf of such members or related entities all compliance responsibility for that function or those functions, including all reporting requirements.

Coordinated Functional Registration (CFR)[66]: In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more reliability standard and/or for one or more requirements/sub-requirements within particular reliability standards applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The registration of the CFR is the complete registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or requirements/sub-requirements it has registered for in the CFR. Due to abrupt or forced registration changes, as described below, this form of registration may become more common in 2012.

Results of Abrupt or Forced Registration Changes

The conclusions drawn from a of the EOP-005 System restoration and Blackstart Compliance Analysis Report completed by NERC indicate that an increasing number of self-reported Possible Violations (PVs) are being issued due to abrupt or forced registrations.

As such, these types of PVs involve a heavier case load for Registered Entities, as some of the violations require lengthy mitigation plans. Furthermore, for issues that involve certifiable functions, a NERC certification must be completed per the Rules of Procedure.

NERC and the Regional Entities will continue to work together in the development of appropriate actions to efficiently manage the compliance issues resulting from abrupt and forced registration changes.

[65] Section 507 of the NERC RoP, http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110412.pdf
[66] Section 508 of the NERC RoP, http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110412.pdf

The Compliance Enforcement Initiative

After five years as the ERO, NERC continues to seek ways to improve and adapt its processes and Reliability Standards. NERC, FERC and the industry have discussed significant ways to retool efficiency efforts through multiple technical conferences. A key outcome was the recognition that compliance matters should be treated differently based on the level of risk posed to the reliability of the BPS.

NERC's new Compliance Enforcement Initiative (CEI) is designed to handle issues more efficiently, focus on issues posing a higher risk to reliability, streamline administrative paperwork, and continue to encourage self-reporting and mitigation.

NERC is not looking to reduce the number of compliance items identified with this new initiative, but is rather looking to treat matters differently based upon the risk associated with them. By identifying, mitigating and resolving issues that do not pose a serious risk to the reliability of the BPS, more resources can be focused on violations that do pose a risk to reliability.

The CEI is being launched in accordance with NERC's existing rules and procedures. The new initiative is not about whether issues will be addressed. Rather, it is about how they are addressed.

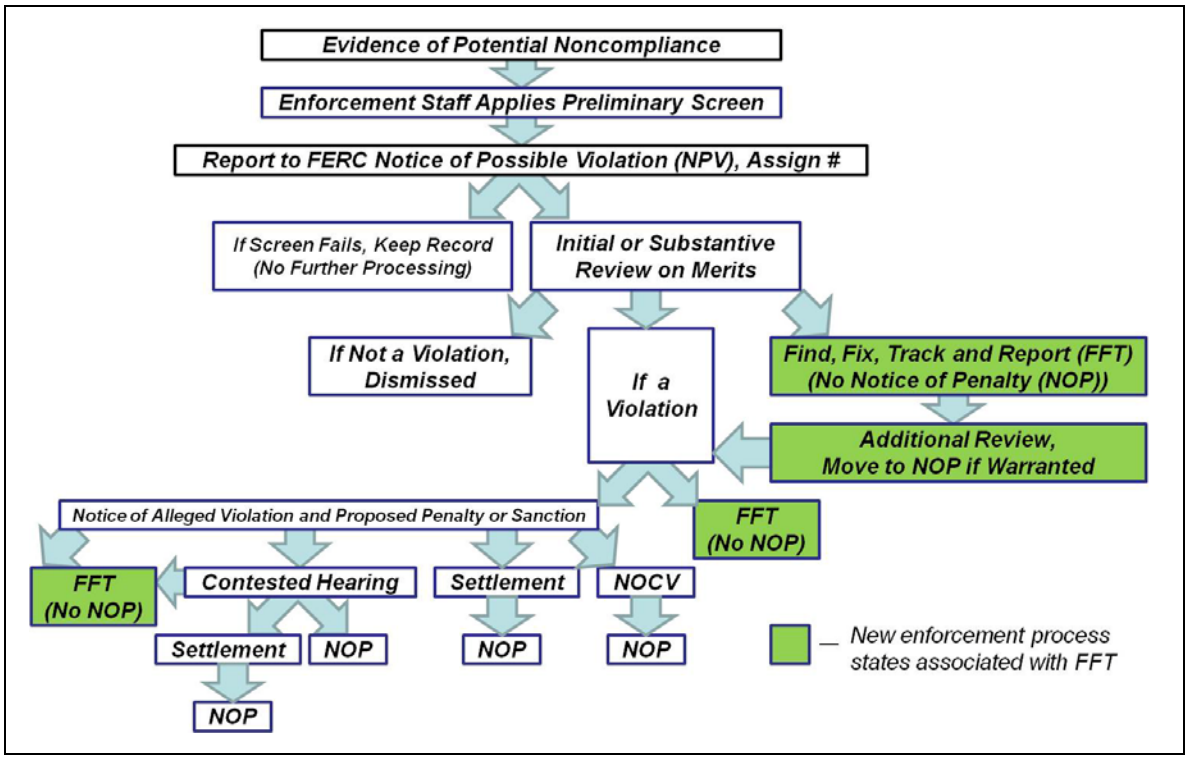


Figure 6: New Enforcement Process incorporating the Find, Fix, Track, and Report (FFT) Approach.

Following NERC's filing[67] of the CEI on September 30, 2011, there will be three possible tracks, see Figure 6, for dealing with compliance matters: Dismissal; Find, Fix, Track and Report (FFT); and Notice of Penalty (NOP). Dismissals occur where there are no violations, when the entity is not registered for and/or subject to a particular requirement, or where there are duplicate entries of issues. No changes are being made with respect to dismissals.

The FFT is the new portion of the compliance initiative. This process will apply when a Possible Violation poses a lesser (minimal to moderate) risk to bulk power system reliability. All matters identified via FFT or NOP must be fixed; the registered entity must provide a statement of completion and completion of mitigation activities is subject to verification by the Regional Entity as part of an audit, spot check or random sampling. The issue must be fixed prior to inclusion in a report to FERC. A Possible Violation processed through the FFT track becomes a remediated issue once included in an FFT informational filing and such filing concludes processing of that matter by Regional Entities and NERC. No penalties or sanctions will be applied to FFT issues. These remediated issues will be included as part of a registered entity's compliance history and will be taken into account in future actions as appropriate. Mitigation activities must be described in the FFT spreadsheet; however, a formal mitigation plan will not be required.

For those matters that pose a more serious risk to reliability of the bulk power system, NOPs will be filed. They may be filed either in a spreadsheet format or a full NOP format.

Regions will review current cases and determine which disposition approach will be used based on the issue. Training of compliance and enforcement staff will take place as part of Phase I, which is targeted to occur over a 12-18 month period after the initial kickoff of the CEI at the end of September 2011. During Phase I, compliance staff may make recommendations to enforcement staff for ultimate disposition of an issue as part of an FFT or NOP. In Phase II, both compliance and enforcement staff may determine the ultimate disposition of an issue.

Almost 70 percent of violations are a result of four compliance monitoring methods (self-report, self-certification, data-submittal and exception-reporting) that provide self-identified possible violation reporting by a registered entity. NERC encourages registered entities to include a full factual description of the issue, detailed information regarding mitigation activities, identification of the potential and actual risk posed as well as mitigating factors in effect while a Possible Violation is awaiting a determination of which processing track it will be treated with. This will help illustrate that the registered entity understands the full scope of the violation and has taken actions to correct it and prevent recurrence.

[67] *See* North American Electric Reliability Corporation, "Petition Requesting Approval of New Enforcement Mechanisms and Submittal of Initial Informational Filing Regarding NERC's Efforts to Refocus Implementation of its Compliance Monitoring and Enforcement Program": http://www.nerc.com/files/FinalFiled_CEI_Document_20110930.pdf

NERC will continue to compile trend data and keep historical records on registered entities, which will allow NERC to target areas for increased education as needed. Registered entities are expected to provide information that is sufficient, complete and validated to support the issues identified for FFT or NOP treatment.

The CEI, featuring the FFT approach to lesser risk remediated issues, is a paradigm shift in how issues are processed, not whether they are addressed. In all cases, they must be found, fixed and tracked. The CEI reflects a risk-based approach that acknowledges all Possible Violations are not equal and should not be treated as such. By focusing resources on violations that have a serious risk to the reliability of the bulk power system, NERC is able to better fulfill its mission as the ERO.

Events Analysis Interface with Compliance

To support a strong culture of compliance, registered entities are expected to perform a compliance analysis and to develop a compliance self-assessment report proportional to the significance of the event/risk to the BPS for categorized events in which there could be a gap between actual system or human performance and the requirements of NERC or regional reliability standards. Registered entities are encouraged to submit a compliance self-assessment report to the Regional Entity compliance liaison proportional to the significance of the event/risk to the BPS for categorized events. This report should encompass a sufficiency review, proportional to the event's significance, of applicable standards associated with the event.

Registered entities who make a good faith effort to self-identify and self-disclose possible violations stemming from their event analyses will be afforded consideration in any enforcement action in accordance with NERC's Sanction Guidelines. If further analysis by the Regional Entity or NERC reveals other possible violations, the registered entity's participation and cooperation will be noted and considered.

For this reason, it is recommended that registered entities establish a liaison between their internal event analysis and compliance functions. This will provide a clearer understanding and a more efficient transfer of information from both an operational and a compliance standpoint, and it will facilitate a thorough standards review by the registered entity.

To facilitate the development of a rigorous self-assessment, NERC Events Analysis has developed the Compliance Analysis Template, which is found in Appendix G of its process.[68] Additionally, this Compliance Analysis Template is attached below as Appendix 5.

[68] *See* page 35, Appendix G, "Electric Reliability Organization Event Analysis Process": http://www.nerc.com/files/2011-05-02%20Event_Analysis_Process_Phase%202%20Field%20Test%20Draft%20-%20Final%20-%20For%20posting.pdf

Regional Entities CMEP Implementation Plans

The Regional Entities Implementation Plan is an annual plan, submitted to NERC no later than October 1 of each year for approval that, in accordance with NERC RoP Section 401.6 and the NERC CMEP Implementation Plan, identifies:

1. All Reliability Standards identified by NERC in the 2012 CMEP Actively Monitored Reliability Standards list.
2. Other Reliability Standards proposed for monitoring by the Regional Entity; these will include any regional Reliability Standards and additional NERC Reliability Standards.
3. The methods to be used by the Regional Entity for reporting, monitoring, evaluation, and assessment of performance criteria with each Reliability Standard. NERC expects at a minimum for the Regional Entities to perform the compliance monitoring methods identified in the NERC 2012 Actively Monitored Reliability Standards list. When a Regional Entity determines that an increased audit scope is necessary, then the Regional Entity shall notify the registered entity of the increased audit scope. This notification shall be part of the audit notification package and shall include the Reliability Standards and Requirements that are included in the increased scope, as well as the justification for the increased scope. When a Regional Entity determines that an increased audit scope is necessary after the notification package is sent, or while the audit team is on-site, then the Regional Entity shall notify the registered entity of the increased audit scope as soon as possible. For references to NERC guidance or Implementation Plans such as the CIP Guidance, a link should be included in the Regional Entity Implementation Plan instead of listing the entire document.
4. The Regional Entity's Annual Implementation Plan should include a list of registered entity names that are on the 2012 schedule, NERC Compliance Registration ID, and the year they will be audited. The Regional Entity can provide its audit plan for multiple years in the future.
5. The Regional Entity's Annual Plan should address Key CMEP Activities and Initiatives.

Conclusion

The ERO CMEP Implementation Plan, which is developed according to Section 215(c) of the Federal Power Act, is the operating plan for annual compliance monitoring and enforcement activities. NERC, as the international ERO, and the Regional Entities through their delegation agreements with NERC, monitor and enforce compliance of registered entities with all regulatory approved Reliability Standards. Registered entities include all BPS owners, operators and users.

While the actions of the ERO in accordance with the CMEP are critical to the reliability of the BPS, it is only one part of an overall plan to ensure system reliability. The other part consists of the actions of the registered entities and the electric power industry at large, and these are equally as critical to system reliability. The registered entities must participate in the educational, informational and developmental efforts that are being undertaken not only to maintain reliability, but to enhance it as well. The sharing of the industry's technical expertise, experience, and judgment as well as its participation in the ERO's processes will help to further identify and remove reliability gaps and shortcomings. The ERO continuously seeks to improve the execution of its role in ensuring system reliability, as is the case with the advancements of the annual CMEP Implementation Plan undertaken for 2012, but the industry must continue to participate for the overall reliability plan to be successful.

REVISION NUMBER	DATE	NATURE OF CHANGE	REVIEWER	APPROVAL
0	5/5/2011	Original Development	Jacki Power Craig Struck Kyle Howells Jodi Ernst	Michael Moon
0.1	6/3/11	Incorporated appropriate comments from NERC staff.	Jacki Power Craig Struck Kyle Howells	Michael Moon
0.2	6/25/11	Incorporated appropriate comments from FERC, Compliance and Certification Committee, and Regional Entities.	Jacki Power Craig Struck Kyle Howells	Michael Moon
0.3	6/30/11	Final review for content and formatting. Changed from Draft document to working document.	Jacki Power Craig Struck Kyle Howells Caroline Clouse	Michael Moon
0.4	7/5/11	Added references to Regional Entity input into AML and Implementation Plan on pages 6, 11, 12, and 16.	Craig Struck	Michael Moon
0.5	7/12/11	Incorporated appropriate comments from the NERC Board of Trustees Compliance Committee.	Craig Struck Kyle Howells Jodi Ernst	Michael Moon
0.6	8/1/11	Original posting. Editorial corrections made to Figure 5, Compliance Processes, on page 36.	Craig Struck	Michael Moon
0.7	8/25/11	Revised posting. Updates to Table 6 and Appendix 2 to reflect minor revisions to the 2012 AML as well as minor editorial corrections to the Implementation Plan	Kyle Howells	Michael Moon
1.0	10/19/11	Revised posting. Incorporated a description of the Compliance Enforcement Initiative as well as the Events Analysis Interface with Compliance. Updated the basis for NUC-001 inclusion into the 2012 AML.	Kyle Howells	Michael Moon
1.1	10/26/11	Updated Events Analysis Interface with Compliance language	Kyle Howells	Michael Moon
1.2	12/14/11	Incorporated guidance concerning the audits of entities registered as a PSE on pages 21 and 28	Craig Struck	Michael Moon
1.3	1/9/12	Updated Tables 6, 8, 9, 10, and 11 as well as Figures 6 and 7 based upon retirement of EOP-001-0 R2.	Kyle Howells	Michael Moon

Appendix 1 – 2012 ERO High-Risk Priorities with High Value Associated Reliability Standards

The ERO high-risk priorities are those current issues challenging the BPS. These issues have been identified through the analysis of significant events on the BPS, such as the August 2003 blackout, and the execution of compliance actions in addition to input provided by numerous groups, including the Regional Entities, NERC's CEO, and many other industry stakeholders. Additionally, recent events within North America have highlighted several areas of importance within the BPS, and the lessons learned and circumstances surrounding these events have been taken into account as well. Therefore, the high-risk priorities are as follows:

1. **Misoperations of relay protection and control systems** – Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. Protection systems are designed to operate reliably when needed under the presence of a fault on the system, to quickly isolate a piece of equipment or a 'zone' of the BPS, without allowing the fault to transfer into adjoining facilities. The greater the number of facilities involved in an event, the more severe the impact to the rest of the BPS, with cascading failure such as the "Zone 3 Relay" issue in the August 2003 blackout being the extreme. Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization. Adding to the risk is that system protection is an extremely complex engineering field – there are many practitioners but few masters.

2. **Human errors by field personnel** – Field personnel play an important role in the maintenance and operation of the BPS. They often switch equipment in and out of service and align alternative configurations. Risks can be introduced when field personnel operate equipment in a manner that reduces the redundancy of the BPS, sometimes even creating single points of failure that would not exist normally. Taking outages of equipment to conduct maintenance is a routine and necessary part of reliable BPS operation. However, any alterations to the configuration of the network must be carefully planned in advance to minimize loss of redundancy and avoid unintended single points of failure. It is also important that such changes and risks be communicated to system operators and reliability coordinators in advance, so that they can make adjustments in their operating plans and reliability assessments.

3. **Ambiguous or incomplete voice communications** – Out of longstanding tradition, system operators and reliability coordinators are comfortable with informal communications with field and power plant personnel and neighboring systems. Experience from analyzing various events indicates there is often a sense of awkwardness when personnel transition from conversational discussion to issuing reliability instructions. It is also human nature to be uncomfortable in applying formal communication procedures after personnel have developed informal styles over many years. Confusion in making the transition from normal conversation to formal communications can introduce misunderstandings and possibly even incorrect actions or assumptions. Further, once the need to transition to more formal structure is recognized, the transition is often not complete or effective. Results can include unclear instructions, confusion as to whether an instruction is a suggestion or a directive, whether specific action is required or a set of alternative actions are permissible, and confusion over what elements of the system are being addressed.

4. **Right-of-way maintenance** – The August 14, 2003 blackout highlighted effective vegetation management programs as a key recommendation for avoiding future cascading failures. More broadly, any encroachments in the right-of-way that reduce clearances to the point of lowering facility ratings or reducing the randomness of possible contacts can be a risk to reliability. Although these impacts may not always be readily apparent, under extreme wind and temperature conditions they may become more of a risk to BPS reliability. There are many challenges to effective right-of-way maintenance, especially maintaining proper clearances, including interventions by private landowners, local municipalities, and federal and state landowners.

5. **Changing resource mix** – Energy and environmental policies along with energy markets are driving proposals toward unprecedented changes in the resource mix of the BPS. Examples include integration of significant amounts of renewable energy (variable such as wind and solar), natural gas, storage and demand resources to provide energy and capacity. Industry's knowledge of the characteristics of the BPS comes from nearly a century of operational experience with the existing resource mix. However, integration of these new resources results in operating characteristics significantly different from conventional steam production facilities. An array of reliability services must be provided over a range of time horizons from seconds to minutes to hours and days, and annually such as load following, contingency reserves, frequency response, reactive supply, capacity and voltage control, and power system stability. Continued reliable operation of the BPS will require an industry dialog with policymakers and regulators. Understanding the impacts on reliability will depend on accurate modeling of new resources, and development of new methods and tools for the provision of essential reliability services.

6. **Integration of new technologies** – While the electric utility industry was once thought to be slow in adopting new technologies, smart grid initiatives across the country have proven this not be the case as of late. To continue this proactive trend of incorporating new technologies as well as to ensure proper coordination, a number of Reliability Standards should be considered in order to make this priority possible. Introduction of electric vehicles, demand-side management, variable generation, distributed resources and smart grid technologies presents tremendous opportunities but also introduces changes to the operating characteristics of the BPS. Integration of these new technologies requires changes in the way the BPS is planned and operated to maintain reliability. Further, additional tools/models are required to support their integration to meet policy and strategic goals. Without these changes, it will be challenging to maintain reliability with large-scale deployments. For example, some smart grid devices/systems increase exposure to cyber threats, while variable generation requires additional ancillary services. Integration of these new technologies must be achieved in a manner that does not undermine existing levels of stability, resilience and security of the BPS.

7. **Preparedness for -impact, low-frequency events** – Although there is a wide range of threats labeled "high-impact, low-frequency," the greatest concern is being prepared for possible events that could debilitate the BPS for extended periods, such as widespread, coordinated physical/cyber attacks or geomagnetic storms. The industry must consider improving the design of the BPS to address these potential risks, prepare coordinated North American response plans for use during catastrophic events, and be ready to deploy those plans to restore essential services in a timely manner.

8. **Non-traditional threats via cyber-security vulnerabilities –** Establishment of enterprise risk-based programs, policies and processes to prepare for, react to, and recover from cyber-security vulnerabilities is a high priority for the industry. The BPS has not yet experienced wide-spread cyber-attacks, and a contributing factor has been the traditional physical separation between the industrial control system/SCADA environment and the business and administrative networks. This situation, however, is rapidly changing, predominantly due to the efficiencies that can be achieved by leveraging shared networks and resources, so now even physically separated environments are susceptible. For example, the BPS could be as vulnerable to digital threats as IT systems, but with far more critical implications, as the recent Stuxnet virus has shown. Disabling or turning systems off in a binary fashion is concerning enough, but as illustrated by Stuxnet, industrial control system software can be changed and data can be stolen without intrusions even being detected. These injection vectors serve as a blueprint for future attackers who wish to access controllers, safety systems, and protection devices to insert malicious code-targeting changes to set points and switches as well as alteration or suppression of measurements.

9. Other

Certain considerations that have potentially high impacts to reliability do not fit cleanly into other categories. Such considerations include the Frequency Response Initiative and Winter Weather Events from the Southwest and Texas in February of 2011. The Reliability Standards relating to these considerations, especially those corresponding to emergency procedures, are important in terms of enacting lessons learned and preventing detrimental conditions in the future.

NERC has identified a number of Reliability Standards associated with each of the ERO high-risk priorities. These associated Reliability Standards have a high value in that they most directly address the concerns raised by the high-risk priorities. The relationships of these high-value Reliability Standards to the high-risk priorities are laid out in the list below.

1. Ambiguous, Incomplete Voice Communications
    - COM-002
    - EOP-002
    - EOP-005
    - EOP-006
    - EOP-008
    - IRO-002
    - IRO-006
    - TOP-002

2. Mis-Operations of Relay and Controls Systems
    - EOP-005
    - EOP-008
    - FAC-001
    - PRC-001
    - PRC-004
    - PRC-005
    - PRC-023
    - TPL-003
    - TPL-004

3. Human Errors by Field Personnel
    - COM-002
    - EOP-005
    - EOP-008
    - FAC-003
    - PER-002

4. High-Priority CIP and Supporting Standards
    - CIP-001
    - CIP-002
    - CIP-005
    - CIP-006
    - CIP-007
    - COM-001
    - COM-002
    - EOP-005
    - EOP-008

5. Right-of-Way Maintenance and Clearances
    - FAC-003
    - FAC-008
    - FAC-009
    - TOP-002
    - TPL-003
    - TPL-004

6. Changing Resource Mix
    - EOP-001
    - EOP-005
    - EOP-002
    - IRO-002
    - TOP-002

7. High-Impact, Low-Frequency Events
    - EOP-003
    - EOP-005
    - EOP-008
    - IRO-004
    - IRO-005
    - NUC-001
    - TOP-004
    - TOP-007

8. Other
    - Frequency response initiative
        - BAL-003
    - Winter Weather Events (Texas, February 2011)
        - BAL-002
        - EOP-001
        - EOP-002
        - EOP-004
        - EOP-005

9. Integration of New Technologies
    - COM-001
    - FAC-001
    - FAC-002
    - FAC-009
    - IRO-002
    - PRC-001

Appendix 2 – 2012 Actively Monitored List (AML) Analysis

As with the Reliability Standards selected for audit in 2012, the Reliability Standards selected for annual self-certification in 2012 represent the results of a risk-based approach. Due to the breadth of the AML, it can be helpful to perform targeted analysis in order to corroborate that the ERO priorities are being properly addressed. As a synopsis of the AML, Table 8 shows a breakdown of the applicable requirements within the AML for 2012 and in years past. The average number of Requirements per function for 2012 has been reduced substantially from previous years. In fact, since the CIPs have been incorporated into the AML in 2010, the average number of Requirements by function has been reduced to half of its maximum; there were an average of 167 Requirements to be audited per function in 2010 while there are 84 in 2012.

Table 8: Requirements Analysis for the 2012 AML and those going back to 2007

	Requirements Analysis								
Function	Total Applicable Reqs as of 1/9/2012	**2012 AML (All Reqs)**	**2012 AML (CIP only)**	**2012 AML (693 only)**	2011	2010	2009	2008	2007
TOP	498	170	109	61	246	321	134	142	115
RC	398	136	109	27	203	299	97	131	76
BA	408	155	109	46	206	305	107	175	95
TO	368	134	107	27	222	271	70	86	86
GO	302	119	107	12	198	242	34	47	40
GOP	254	121	109	12	168	242	27	38	13
TSP	318	166	107	59	202	206	5	7	2
RSG	20	2	0	2	0	6	6	20	20
PA/PC	178	6	0	6	42	88	56	89	86
TP	143	13	0	13	49	83	51	86	86
IA	184	107	107	0	145	168	0	0	0
RP	22	3	0	3	3	0	0	0	0
LSE	267	123	109	14	157	214	12	26	13
PSE	11	1	0	1	1	3	3	4	3
DP	128	9	0	9	51	54	21	51	51
Avg Reqs	233	84	65	19	126	167	42	60	46

When looking at the total number of in-effect Requirements as of January 9, 2012 within the 2012 AML as applicable by function, there is a strong correlation between the potential reliability impact of a function and the proportion of its applicable Requirements that are represented on the 2012 AML. For instance, the Reliability Coordinator, Balancing Authority, and Transmission Operator certified functions, all have over 30% of their applicable Requirements on the AML. For other functions, such as the Purchasing-Selling Entity (PSE) or Distribution Provider (DP), a much smaller proportion of their Reliability Standards is incorporated. These results are shown in Table 9.

In some cases, such as the TSP, Generator Operator (GOP), Interchange Authority (IA), and Load-Serving Entity (LSE), there is perhaps an unexpectedly high percentage of applicable Reliability Standards within the 2012 AML. The TSP has a large number due to the inclusion by FERC Order 729 of MOD-001, MOD-004, and MOD-008, which alone count for 76 Requirements. The GOP, IA, and LSE functions have a large proportion of Requirements due to

CIP. Looking at Table 10, which is similar to Table 9 but accounts only for 693 Reliability Standards, the GOP, IA, and LSE functions are shown to have 15%, 0%, and 15% of applicable 693 Requirements within the 2012 AML respectively, which are much more reasonable numbers.

Table 9: Percent of total in effect Requirements as of 1/9/2012 represented in the 2012 AML

	Requirements Analysis		
Function	Total Applicable Reqs as of 1/9/2012	2012 AML (All Reqs)	% of Total
TOP	498	170	34%
RC	398	136	34%
BA	408	155	38%
TO	368	134	36%
GO	302	119	39%
GOP	254	121	48%
TSP	318	166	52%
RSG	20	2	10%
PA/PC	178	6	3%
TP	143	13	9%
IA	184	107	58%
RP	22	3	14%
LSE	267	123	46%
PSE	11	1	9%
DP	128	9	7%

Table 10: Percent of total in effect 693 Requirements as of 1/9/2012 represented in the 2012 AML

	Requirements Analysis		
Function	Total Applicable 693 Reqs as of 1/9/2012	2012 AML (693 Reqs)	% of Total
TOP	326	61	19%
RC	226	27	12%
BA	236	46	19%
TO	200	27	14%
GO	134	12	9%
GOP	82	12	15%
TSP	150	59	39%
RSG	20	2	10%
PA/PC	178	6	3%
TP	143	13	9%
IA	16	0	0%
RP	22	3	14%
LSE	95	14	15%
PSE	11	1	9%
DP	128	9	7%

Table 11 shows that only 29.72% of all Requirements within the three tier structure are included in the 2012 AML, which is represented by Tier 1 Requirements.

Table 11: Requirement counts by Tier

2012 AML - Tier 1	Tier 2	Tier 3
274	398	253

The following figures, Figure 6 and 7, display the information discussed already, but provides it in a different format for ease of comparison. Figure 6 displays the number of AML Requirements by registered function across all years of mandatory compliance in addition to the total number of applicable Requirements as of January 9, 2012. Figure 7 shows the same information, but only for the 2012 AML and the total number of applicable Requirements as of January 9, 2012.

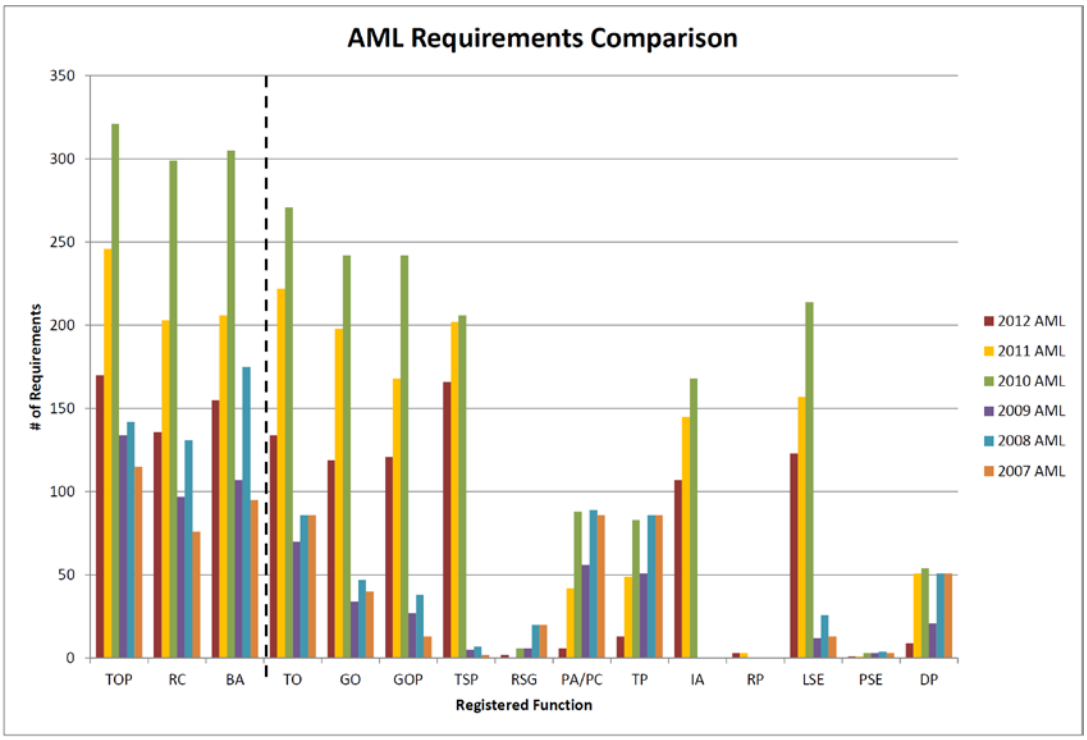


Figure 6: Number of applicable Requirements to each function within a given year's AML and for all Requirements currently in effect.

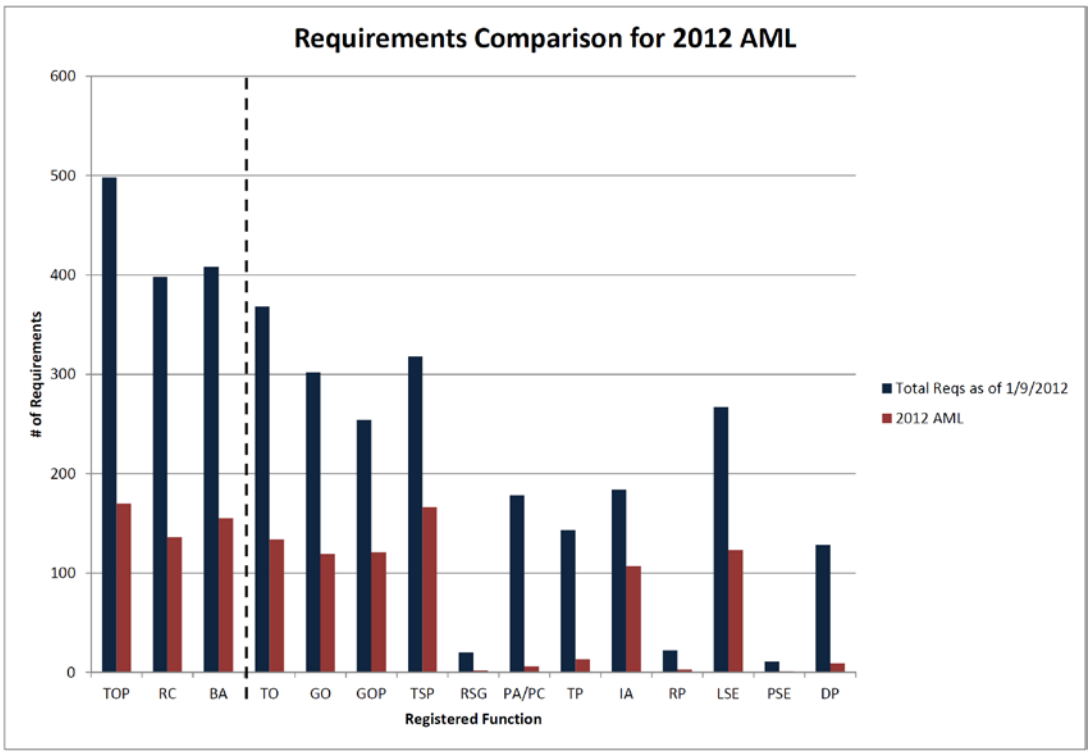


Figure 7: Direct comparison of Requirements in the 2012 AML as compared to all in effect Requirements as of 1/9/2012.

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Appendix 3 – 2012 Regional Entity Request to Defer or Reduce the Scope of a Compliance Audit

Request to Reduce Scope or Deferment of a Compliance Audit
This form should be submitted as both a Word and PDF file to NERC Compliance Operations at least 90 days prior to the audit for approval. Email forms to Jacki.Power@nerc.net and Stacia-Ann.Chambers@nerc.net

Requesting Regional Entity Information

Date:	
Name:	
Title:	
Region:	
State the basis for Reduced Audit Scope or Deferment of Compliance Audit:	
State other methods used for compliance monitoring during period of reduced scope or deferment?	
State requested duration of deferment, if applicable.	
State whether this is a MRRE audit?	
Applicable Region(s):	FRCC ☐ MRO ☐ NPCC ☐ RFC ☐ SERC ☐ SPP ☐ TRE ☐ WECC ☐

Registered Entity Information

Registered Entity's Legal Name:	
NCR ID Number:	
Date of Last Compliance Audit:	
Date of Next Compliance Audit:	

Regional Entity's Additional Information

Comments:	

Regional Entity Authorized Signature

ERO Analysis Results

State information reviewed and basis for determination	

ERO Final Determination

Approved: ☐ Declined: ☐

ERO, Director of Compliance Operations

Appendix 4 – 2012 CMEP Implementation Plan Survey

Questions to the Regional Entities concerning the 2012 CMEP Implementation Plan

Instructions: Each Regional Entity shall complete the 2012 CMEP Implementation Plan Survey and provide it to NERC no later than January 31, 2013. This feedback is needed as soon as possible, as it will be used as input into the 2014 CMEP Implementation Plan and 2014 budget development.

I. Compliance Monitoring

1. Please provide statistics on the number and types of compliance audits conducted (Please separate CIP from Order 693 audits)
    a. Were all planned audits completed?
        i. If not, please indicate the reasons.
    b. How many compliance audit reports were completed in 2012?
        i. For the 693 compliance audit reports, did you complete them within the CMEP suggested timeframe of 60 days?
        ii. If not, what challenges did you face for completing compliance audit reports?
2. Please provide statistics on the other methods used by the Regional Entity for reporting, monitoring, evaluation, and assessment of performance criteria with each Reliability Standard as indicated by your annual Implementation Plan (Please separate CIP from Order 693).
    a. Were all mandatory Spot Checks completed?
3. Please provide a status of your three-year and six- year Compliance Audit program plan. Is your Regional Entity compliance audit program on schedule?
4. What actions did you take to address the Outstanding Issues list that NERC issues each month?
5. Do you have processes in place to monitor the progress of settlement negotiations to make sure they are progressing well?

II. Compliance Outreach

6. Please provide statistics on your Regional Compliance Workshop.
    a. How many workshops?
    b. Number of participants?
    c. What feedback was received from the workshops?
    d. What should be added to the workshops?
7. Describe any other communication mediums used to promote the consistency and transparency of the NERC Compliance Program for 2012?
    a. How successful were your consistency and transparency efforts?

b. What improvements are planned for 2013?

III. Compliance Enforcement

8. Please describe any efforts you have undertaken to improve the efficiency of your compliance enforcement process.
    a. Utilization of NERC's streamlined enforcement templates (disposition documents, settlement templates)
    b. Participation in the administrative citation program
    c. Staffing and other initiatives to improve efficiency
10. Please describe any efforts you have undertaken to improve mitigation of Reliability Standards violations.
    a. Encouragement of prompt submission of mitigation plans
    b. Monitoring of mitigation plan completion and encouragement of early mitigation plan completion
11. What has been your experience with the effectiveness of penalty and sanctions levied to incite compliance and eliminate repeat offenders?
12. What has been your experience in moving violations back into the Notice of Confirmed Violation and Proposed Penalty or Sanction (NOCV) process by ceasing negotiations and issuing a Notice of Alleged Violation and Proposed Penalty or Sanction (NAVAPS)?

IV. Program Effectiveness

13. Describe any general observations, best practices, lessons learned, and trends for the Regional Entities as well as registered entities.
14. Describe any significant changes (e.g. process, communication changes) from the 2011 program that were implemented in your 2012 Regional Compliance Program.
    a. What were the positive and/or negative experiences associated with these changes, if any?
15. Discuss any significant challenges encountered in 2012, describe the action taken, or suggest potential remedial actions.

V. Events Analysis and Compliance Reviews

16. How many events analyses were conducted in 2012 within your region?

VI. Projection for the Future

17. What changes would you propose to reduce the 2013 Actively Monitored List? How would you revise the risk-based criteria?
18. Do you have any specific recommendations for the NERC Compliance Monitoring and Enforcement Program that you would like to include in the NERC annual report this year?
19. How do you plan to address the "risk-based" approach in your auditing program?
20. What type of budget issues did you face in implementation of the 2012 CMEP? Are there any budgetary issues that need to be addressed for 2013

Appendix 5 – Events Analysis Process Appendix G - Compliance Assessment Template

Events Analysis Process Appendix G - Compliance Assessment Template

The registered entity's compliance function is expected to perform an initial compliance assessment, concurrent with the registered entity's event analysis process.

A systematic, methodical compliance assessment process might include the following steps:

1. Refer to the causes and contributing factors of the event as determined by the registered entity's event analysis process.
2. Identify any applicable Reliability Standards requirement that may have been implicated by the causes and contributing factors of the event.
3. Develop conclusions after reviewing the facts and circumstances of the event that are relevant to step 2 above as they apply to the applicable Reliability Standards requirements.
4. Self-report any findings of non-compliance to the Regional Entity per the CMEP procedures.

Sample Template for Compliance Assessment Summary

Event causes or contributing factors	**Applicable NERC Reliability Standards**	**Details of Compliance Assessment Effort**	**Findings**
Cause	AAA-000-0 Requirement 1	Identify the process used to assess compliance with this requirement. Identify any evidence that demonstrates compliance. Identify any evidence that suggests non-compliance.	Findings of possible violations should be identified. If there are no findings of non-compliance, that should be noted.
	AAA-000-0 Requirement 2		
Contributing factor	BBB-000-0 Requirement 1		

Category 1a Example

Event causes or contributing factors	Applicable NERC Reliability Standards	Details of Compliance Assessment Effort	Findings*
Equipment failure of a high side transformer– cleared along with two transmission lines.	**TOP-002-2a** **R6.** Each BA and TOP shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, sub-regional and local reliability requirements.	Established transfer limits were followed such that the event did not result in instability. The limit for operating across this internal interface is established in the RC. "XYZ Interface All Lines In Stability Guide" (document provided)	No findings of non-compliance.*
Equipment failure of a high side transformer– cleared along with two transmission lines.	**TOP-002-2a** **R10.** Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	No SOLs were violated. There are no IROLs associated with the loss of equipment in this event. See the specific guide referenced in the response to **TOP-002-2a R6**.	No findings of non-compliance.*
Equipment failure of a high side transformer– cleared along with two transmission lines.	**TOP-004-2** **R1.** Each TOP shall operate within the IROLs and SOLs. **R2.** Each TOP shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	The system was operated to remain within transfer limits across the "XYZ" internal interface established as a result of stability studies as delineated in the Transmission Operating Guide developed by RC. See the specific guide referenced in the response to **TOP-002-2a R6**.	No findings of non-compliance*
Equipment failure of a high side transformer– cleared along with two transmission lines.	**PRC-001** **R1.** Each TOP, BA and GOP shall be familiar with the purpose and limitations of protection system schemes applied in its area.	Both the RC and the TOPs are trained on the Transmission Operating Guides as well as relaying and SPSs on the BPS. Protection operated correctly and as planned.	No findings of non-compliance*
Equipment failure of a high side transformer– cleared along with two transmission lines.	**PRC-004** **R1.** The TOP and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	System Protection engineers evaluated the relay operations and determined that all relaying operated correctly and as planned.	No findings of non-compliance*
Equipment failure of a high side transformer– cleared	**TOP-008** **R1.** The TOP experiencing or contributing to an IROL or SOL	R1 Operators used their EMS-based tools to ensure that there were no	No findings of non-compliance*

along with two transmission lines.	violation shall take immediate steps to relieve the condition, which may include shedding firm load. **R2.** Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the TOP shall always operate the BPS to the most limiting parameter. **R3.** The TOP shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the TOP shall notify its RC and all neighboring TOPs impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter. **R4.** The TOP shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The TOP shall use the results of these analyses to immediately mitigate the SOL violation.	SOL/IROL violations. R2 by following the TOP Guides developed by RC, violations do not occur. R3 no conditions occurred that required disconnection. R4 Operators used their EMS-based tools to ensure that there were no SOL/IROL violations.	
Equipment failure of a high side transformer– cleared along with two transmission lines.	**TOP-006** **R2.** Each RC, TOP and BA shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources. **R5** Each RC, TOP and BA shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	The EMSs at both the RC and the TOP provide operators with the information needed to evaluate system conditions and notify operators when conditions are off normal. EMS system visibility and communications were not lost during this event.	No findings of non-compliance*

			*Findings as the outcome of a compliance self-assessment will result in either a statement of "No Findings" or that of "Possible Violation (PV)." Should the latter be the result, the entity will be given the opportunity to self-report the PV to the Regional Compliance Enforcement department, in accordance with the existing procedures set forth in the CMEP. In doing so, the entity self-reporting should inform the Regional Compliance Enforcement department that this has been done consistent with the event analysis process and the completion of a compliance self-assessment (**Appendix G**) to obtain the credit prescribed.

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Number of Reliability Standards					
Year	2007	2008	2009	2010	2011
Compliance Audit	39	60	49	56	39
Self-Certification	39	60	52	60	53
Periodic Data Submittals	--	--	12	13	14
Exception Reporting	--	--	14	19	13
Spot Check	0	0	13	19	1
Subject to Compliance Violation Investigation	--	--	94	95	102
Subject to Self-Reporting	--	--	94	95	102
Subject to Complaint	--	--	94	95	102

2011 CMEP Reliability Standards Summary			
Reliability Standards (FERC Approved)	Self-Certification Annual (A)	Annual Program Audit (X)	Spot Check (SC)
BAL-001-0.1a			
BAL-002-0			
BAL-003-0.1b			
BAL-004-0			
BAL-005-0.1b			
BAL-006-1.1			
CIP-001-1	A	X	
CIP-002-3, Effective 10/1/2010	A	X	
CIP-003-3, Effective 10/1/2010	A	X	
CIP-004-3, Effective 10/1/2010	A	X	
CIP-005-3, Effective 10/1/2010	A	X	
CIP-006-3c, Effective 10/1/2010	A	X	
CIP-007-3, Effective 10/1/2010	A	X	
CIP-008-3, Effective 10/1/2010	A	X	
CIP-009-3, Effective 10/1/2010	A	X	
COM-001-1.1	A	X	
COM-002-2	A	X	
EOP-001-0			
EOP-002-2.1	A	X	
EOP-003-1	A	X	
EOP-004-1			
EOP-005-1	A	X	
EOP-006-1	A		
EOP-008-0	A	X	
EOP-009-0			
FAC-001-0	A		
FAC-002-0			
FAC-003-1	A	X	
FAC-008-1	A	X	
FAC-009-1	A	X	
FAC-010-2.1 Effective 4/19/2010			
FAC-011-2 Effective 4/29/2009			
FAC-013-1			
FAC-014-2	A		
INT-001-3			
INT-003-2			
INT-004-2			
INT-005-3 Effective 7/1/2010			
INT-006-3 Effective 7/1/2010			
INT-007-1			
INT-008-3 Effective 7/1/2010			
INT-009-1			
INT-010-1			
IRO-001-1.1			
IRO-002-1	A		
IRO-003-2	A		
IRO-004-1	A	X	

IRO-005-2	A	X	
IRO-006-4.1			
IRO-014-1			
IRO-015-1			
IRO-016-1			
MOD-001-1 Effective 4/1/2011	A	X	
MOD-004-1 Effective 4/1/2011	A	X	
MOD-006-0.1 Retired 3/31/2011			
MOD-007-0 Retired 3/31/2011			
MOD-008-1 Effective 4/1/2011	A	X	
MOD-010-0			
MOD-012-0			
MOD-016-1.1			
MOD-017-0.1			
MOD-018-0			
MOD-019-0.1			
MOD-020-0			
MOD-021-0.1			
MOD-028-1 Effective 4/1/2011	A		
MOD-029-1 Effective 4/1/2011	A		
MOD-030-2 Effective 4/1/2011	A		
NUC-001-2 Effective 4/1/2010	A		SC
PER-001-0.1	A		
PER-002-0	A	X	
PER-003-0	A		
PER-004-1	A	X	
PRC-001-1	A	X	
PRC-004-1	A	X	
PRC-005-1	A	X	
PRC-007-0			
PRC-008-0	A	X	
PRC-009-0			
PRC-010-0			
PRC-011-0	A	X	
PRC-015-0			
PRC-016-0.1			
PRC-017-0	A	X	
PRC-018-1			
PRC-021-1			
PRC-022-1			
PRC-023-1 Effective 7/1/2010	A	X	
TOP-001-1	A		
TOP-002-2a	A	X	
TOP-003-0			
TOP-004-2	A	X	
TOP-005-1.1			
TOP-006-1	A		
TOP-007-0			
TOP-008-1			
TPL-001-0.1	A		
TPL-002-0a	A	X	
TPL-003-0a Effective 4/23/2010	A	X	
TPL-004-0			
VAR-001-1	A	X	
VAR-002-1.1b	A	X	

Note: The Reliability Standards listed for the above monitoring methods does not necessarily imply all requirements are included in the 2011 Reliability Standard Actively Monitored list. Refer to the "Requirements Detail Tab" for specifics concerning each Reliability Standard monitoring details.

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2011 Compliance Monitoring and Enforcement Program Requirements Spreadsheet

Compliance is required with all regulatory authority approved Reliability Standards whether or not included in the subset of reliability standards and requirements designated to be audited in the NERC implementation plan. All requirements are subject to a possible CVI, Self-Report, or Complaint.

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)	2011 Annual Program Audit (X)	*2010 Annual Program Audits*	*2009 Annual Program Audits*	*2008 Annual Program Audits*	*2007 Annual Program Audits*
			RESOURCE AND DEMAND BALANCING											
BAL-001-0.1a	R1.		Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control	MEDIUM	BA		M						*X*	*X*
BAL-001-0.1a	R2.		Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a	MEDIUM	BA		M						*X*	*X*
BAL-001-0.1a	R3.		Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and	LOWER	BA								*X*	*X*
BAL-001-0.1a	R4.		Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective,	LOWER	BA								*X*	*X*
BAL-002-0	R1.		Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied	HIGH	BA, RSG		Q				*X*	*X*	*X*	*X*
BAL-002-0		R1.1.	A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the	HIGH	BA, RSG		Q				*X*	*X*	*X*	*X*
BAL-002-0	R2.		Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:	MEDIUM	RRO, RSG		Q				*X*	*X*	*X*	*X*
BAL-002-0		R2.1.	The minimum reserve requirement for the group.	HIGH	RRO, RSG		Q				*X*	*X*	*X*	*X*
BAL-002-0		R2.2.	Its allocation among members.	LOWER	RRO, RSG		Q						*X*	*X*
BAL-002-0		R2.3.	The permissible mix of Operating Reserve - Spinning and Operating Reserve - Supplemental that may be included in Contingency Reserve.	LOWER	RRO, RSG		Q						*X*	*X*
BAL-002-0		R2.4.	The procedure for applying Contingency Reserve in practice.	LOWER	RRO, RSG		Q						*X*	*X*
BAL-002-0		R2.5.	The limitations, if any, upon the amount of interruptible load that may be included.	LOWER	RRO, RSG		Q						*X*	*X*
BAL-002-0		R2.6.	The same portion of resource capacity (e.g., reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by	MEDIUM	RRO, RSG		Q						*X*	*X*

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Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)	2011 Annual Program Audit (X)	*2010 Annual Program Audits*	*2009 Annual Program Audits*	*2008 Annual Program Audits*	*2007 Annual Program Audits*
BAL-002-0	R3.		Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.	HIGH	BA, RSG		Q				*X*	*X*	*X*	*X*
BAL-002-0		R3.1.	As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single	HIGH	BA, RSG		Q				*X*	*X*	*X*	*X*
BAL-002-0	R4.		A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable	MEDIUM	BA, RSG		Q						*X*	*X*
BAL-002-0		R4.1.	A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE	MEDIUM	BA, RSG		Q						*X*	*X*
BAL-002-0		R4.2.	The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an	No VRF Assigned	BA, RSG		Q						*X*	*X*
BAL-002-0	R5.		Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition	LOWER	RSG		Q						*X*	*X*
BAL-002-0		R5.1.	The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its	No VRF Assigned	RSG		Q						*X*	*X*
BAL-002-0		R5.2.	The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its	No VRF Assigned	RSG		Q						*X*	*X*
BAL-002-0	R6.		A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.	MEDIUM	BA, RSG		Q						*X*	*X*
BAL-002-0		R6.1.	The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.	No VRF Assigned	BA, RSG		Q						*X*	*X*
BAL-002-0		R6.2.	The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection	No VRF Assigned	BA, RSG		Q						*X*	*X*
BAL-003-0.1b	R1.		Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency	LOWER	BA						*X*		*X*	*X*
BAL-003-0.1b		R1.1.	The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the	LOWER	BA						*X*		*X*	*X*
BAL-003-0.1b		R1.2.	Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.	LOWER	BA		A	ER			*X*		*X*	*X*

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Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)	2011 Annual Program Audit (X)	*2010 Annual Program Audits*	*2009 Annual Program Audits*	*2008 Annual Program Audits*	*2007 Annual Program Audits*
BAL-003-0.1b	R2.		Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency	MEDIUM	BA						X		X	X
BAL-003-0.1b		R2.1.	The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation.	LOWER	BA						X		X	X
BAL-003-0.1b		R2.2.	The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation.	LOWER	BA						X		X	X
BAL-003-0.1b	R3.		Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability. *See Standard for Approved Interpretation of R3 for WECC WATEC Procedure*	MEDIUM	BA								X	X
BAL-003-0.1b	R4.		Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop	LOWER	BA								X	X
BAL-003-0.1b		R4.1.	Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the	LOWER	BA								X	X
BAL-003-0.1b		R4.2.	The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop	LOWER	BA								X	X
BAL-003-0.1b	R5.		Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated	MEDIUM	BA						X		X	X
BAL-003-0.1b		R5.1.	Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation	MEDIUM	BA						X		X	X
BAL-003-0.1b	R6.		A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area	MEDIUM	BA								X	X
BAL-004-0	R1.		Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be	LOWER	RC								X	
BAL-004-0	R2.		The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error	LOWER	RC								X	
BAL-004-0	R3.		Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:	MEDIUM	BA								X	

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Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)	2011 Annual Program Audit (X)	*2010 Annual Program Audits*	*2009 Annual Program Audits*	*2008 Annual Program Audits*	*2007 Annual Program Audits*
BAL-004-0		R3.1.	The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or	LOWER	BA								*X*	
BAL-004-0		R3.2.	The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz	LOWER	BA								*X*	
BAL-004-0	R4.		Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error	LOWER	RC								*X*	
BAL-004-0		R4.1.	Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the	LOWER	BA			ER					*X*	
BAL-005-0.1b	R1.		All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.	No VRF Assigned	GOP, LSE, TOP								*X*	
BAL-005-0.1b		R1.1.	Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered	MEDIUM	GOP								*X*	
BAL-005-0.1b		R1.2.	Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within	MEDIUM	TOP								*X*	
BAL-005-0.1b		R1.3.	Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a	MEDIUM	LSE								*X*	
BAL-005-0.1b	R2.		Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.	HIGH	BA						*X*		*X*	
BAL-005-0.1b	R3.		A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to	MEDIUM	BA								*X*	
BAL-005-0.1b	R4.		A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the	MEDIUM	BA								*X*	
BAL-005-0.1b	R5.		A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should	MEDIUM	BA								*X*	
BAL-005-0.1b	R6.		The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine	MEDIUM	BA								*X*	
BAL-005-0.1b	R7.		The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become	MEDIUM	BA								*X*	

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Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)	2011 Annual Program Audit (X)	*2010 Annual Program Audits*	*2009 Annual Program Audits*	*2008 Annual Program Audits*	*2007 Annual Program Audits*
BAL-005-0.1b	R8.		The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.	MEDIUM	BA								X	
BAL-005-0.1b		R8.1.	Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of	MEDIUM	BA								X	
BAL-005-0.1b	R9.		The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE	LOWER	BA								X	
BAL-005-0.1b		R9.1.	Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection	LOWER	BA								X	
BAL-005-0.1b	R10.		The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.	HIGH	BA						X		X	
BAL-005-0.1b	R11.		Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled	MEDIUM	BA								X	
BAL-005-0.1b	R12.		Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.	MEDIUM	BA								X	
BAL-005-0.1b		R12.1.	Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon	LOWER	BA								X	
BAL-005-0.1b		R12.2.	Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are	MEDIUM	BA								X	
BAL-005-0.1b		R12.3.	Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more	MEDIUM	BA								X	
BAL-005-0.1b	R13.		Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the	LOWER	BA								X	
BAL-005-0.1b	R14.		The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of	LOWER	BA								X	
BAL-005-0.1b	R15.		The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's	LOWER	BA								X	
BAL-005-0.1b	R16.		The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data	MEDIUM	BA								X	

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BAL-005-0.1b	R17.		Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall	MEDIUM	BA								X	
BAL-006-1.1	R1.		Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.	LOWER	BA								X	
BAL-006-1.1	R2.		Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The	LOWER	BA								X	
BAL-006-1.1	R3.		Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with	LOWER	BA								X	
BAL-006-1.1	R4.		Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly	LOWER	BA		M						X	
BAL-006-1.1		R4.1.	Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:	LOWER	BA		M						X	
BAL-006-1.1		R4.1.1.	The hourly values of Net Interchange Schedule.	LOWER	BA		M						X	
BAL-006-1.1		R4.1.2.	The hourly integrated megawatt-hour values of Net Actual Interchange.	LOWER	BA		M						X	
BAL-006-1.1		R4.2.	Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak	LOWER	BA		M						X	
BAL-006-1.1		R4.3.	A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating	LOWER	BA								X	
BAL-006-1.1	R5.		Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the	LOWER	BA			ER					X	
			CRITICAL INFRASTRUCTURE PROTECTION											
CIP-001-1	R1.		Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the	MEDIUM	BA, GOP, LSE, RC, TOP	A				X	X	X	X	X
CIP-001-1	R2.		Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the	MEDIUM	BA, GOP, LSE, RC, TOP	A				X	X	X	X	X

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CIP-001-1	R3.		Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall provide its operating	MEDIUM	BA, GOP, LSE, RC, TOP	A				X	*X*	*X*	*X*	*X*
CIP-001-1	R4.		Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall establish communications	MEDIUM	BA, GOP, LSE, RC, TOP	A				X	*X*	*X*	*X*	*X*
CIP-002-3, Effective 10/1/2010	R1.		Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010		R1.1.	The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010		R1.2.	The risk-based assessment shall consider the following assets:	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010		R1.2.1.	Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010		R1.2.2.	Transmission substations that support the reliable operation of the Bulk Electric System.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010		R1.2.3.	Generation resources that support the reliable operation of the Bulk Electric System.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010		R1.2.4.	Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010		R1.2.5.	Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010		R1.2.6.	Special Protection Systems that support the reliable operation of the Bulk Electric System.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010		R1.2.7.	Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010	R2.		Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010	R3.		Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			

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CIP-002-3, Effective 10/1/2010		R3.1.	The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010		R3.2.	The Cyber Asset uses a routable protocol within a control center; or,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010		R3.3.	The Cyber Asset is dial-up accessible	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-002-3, Effective 10/1/2010	R4.		Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-003-3, Effective 10/1/2010	R1.		Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-003-3, Effective 10/1/2010		R1.1.	The cyber security policy addresses the requirements in Standards CIP-002-3 through CIP-009-3, including provision for emergency situations.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-003-3, Effective 10/1/2010		R1.2.	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-003-3, Effective 10/1/2010		R1.3.	Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-003-3, Effective 10/1/2010	R2.		Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-003-3, Effective 10/1/2010		R2.1.	The senior manager shall be identified by name, title, and date of designation.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-003-3, Effective 10/1/2010		R2.2.	Changes to the senior manager must be documented within thirty calendar days of the effective date.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-003-3, Effective 10/1/2010		R2.3.	Where allowed by Standards CIP-002-3 through CIP-009-3, the senior manager may delegate authority for specific actions to a named delegate or delegates.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-003-3, Effective 10/1/2010		R2.4.	The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-003-3, Effective 10/1/2010	R3.		Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			

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CIP-003-3, Effective 10/1/2010		R3.1.	Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-003-3, Effective 10/1/2010		R3.2.	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-003-3, Effective 10/1/2010		R3.3.	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-003-3, Effective 10/1/2010	R4.		Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-003-3, Effective 10/1/2010		R4.1.	The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-003-3, Effective 10/1/2010		R4.2.	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-003-3, Effective 10/1/2010		R4.3.	The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-003-3, Effective 10/1/2010	R5.		Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-003-3, Effective 10/1/2010		R5.1.	The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-003-3, Effective 10/1/2010		R5.1.1.	Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-003-3, Effective 10/1/2010		R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-003-3, Effective 10/1/2010		R5.2.	The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-003-3, Effective 10/1/2010		R5.3.	The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-003-3, Effective 10/1/2010	R6.		Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			

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CIP-004-3, Effective 10/1/2010	R1.		Awareness — The Responsible Entity shall establish, document, implement, and maintain a security awareness program to ensure personnel having	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-004-3, Effective 10/1/2010	R2.		Training — The Responsible Entity shall establish, document, implement, and maintain an annual cyber security training program for personnel having authorized	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-004-3, Effective 10/1/2010		R2.1.	This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained prior to their	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-004-3, Effective 10/1/2010		R2.2.	Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004-3, and include, at a minimum, the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-004-3, Effective 10/1/2010		R2.2.1.	The proper use of Critical Cyber Assets;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-004-3, Effective 10/1/2010		R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-004-3, Effective 10/1/2010		R2.2.3.	The proper handling of Critical Cyber Asset information; and,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-004-3, Effective 10/1/2010		R2.2.4.	Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-004-3, Effective 10/1/2010		R2.3.	The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
CIP-004-3, Effective 10/1/2010	R3.		Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-004-3, Effective 10/1/2010		R3.1.	The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.)	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-004-3, Effective 10/1/2010		R3.2.	The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-004-3, Effective 10/1/2010		R3.3.	The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-004-3, Effective 10/1/2010	R4.		Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			

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CIP-004-3, Effective 10/1/2010		R4.1.	The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-004-3, Effective 10/1/2010		R4.2.	The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010	R1.		Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R1.1.	Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R1.2.	For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R1.3.	Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R1.4.	Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R1.5.	Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R1.6.	The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010	R2.		Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R2.1.	These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R2.2.	At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R2.3.	The Responsible Entity shall implement and maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R2.4.	Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			

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CIP-005-3, Effective 10/1/2010		R2.5.	The required documentation shall, at least, identify and describe:	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R2.5.1.	The processes for access request and authorization.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R2.5.2.	The authentication methods.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R2.5.3.	The review process for authorization rights, in accordance with Standard CIP-004-3 Requirement R4.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R2.5.4.	The controls used to secure dial-up accessible connections.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R2.6.	Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010	R3.		Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R3.1.	For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R3.2.	Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010	R4.		Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R4.1.	A document identifying the vulnerability assessment process;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R4.2.	A review to verify that only ports and services required for operations at these access points are enabled;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R4.3.	The discovery of all access points to the Electronic Security Perimeter;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R4.4.	A review of controls for default accounts, passwords, and network management community strings;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			

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CIP-005-3, Effective 10/1/2010		R4.5.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010	R5.		Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R5.1.	The Responsible Entity shall ensure that all documentation required by Standard CIP-005-3 reflect current configurations and processes and shall review the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R5.2.	The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-005-3, Effective 10/1/2010		R5.3.	The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010	R1.		Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R1.1.	All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall")	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R1.2.	Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R1.3.	Processes, tools, and procedures to monitor physical access to the perimeter(s).	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R1.4.	Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R1.5.	Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R1.6.	A visitor control program for visitors (personnel without authorized unescorted access to a Physical Security Perimeter), containing at a minimum the following:	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R1.6.1.	Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R1.6.2.	Continuous escorted access of visitors within the Physical Security Perimeter.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			

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CIP-006-3c, Effective 10/1/2010		R1.7.	Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R1.8.	Annual review of the physical security plan.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010	R2.		Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of hardware at the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R2.1.	Be protected from unauthorized physical access.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R2.2.	Be afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010	R3.		Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010	R4.		Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010	R5.		Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010	R6.		Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010	R7.		Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010	R8.		Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R8.1.	Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R8.2.	Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-006-3c, Effective 10/1/2010		R8.3.	Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			

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CIP-007-3, Effective 10/1/2010	R1.		Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R1.1.	The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R1.2.	The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R1.3.	The Responsible Entity shall document test results.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010	R2.		Ports and Services — The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R2.1.	The Responsible Entity shall enable only those ports and services required for normal and emergency operations.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R2.2.	The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R2.3.	In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010	R3.		Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R3.1.	The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R3.2.	The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010	R4.		Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R4.1.	The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R4.2.	The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			

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CIP-007-3, Effective 10/1/2010	R5.		Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R5.1.1.	The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R5.1.2.	The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R5.1.3.	The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R5.2.	The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R5.2.1.	The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R5.2.2.	The Responsible Entity shall identify those individuals with access to shared accounts.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R5.2.3.	Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R5.3.	At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R5.3.1.	Each password shall be a minimum of six characters.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R5.3.2.	Each password shall consist of a combination of alpha, numeric, and "special" characters.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R5.3.3.	Each password shall be changed at least annually, or more frequently based on risk.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010	R6.		Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			

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CIP-007-3, Effective 10/1/2010		R6.1.	The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R6.2.	The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R6.3.	The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R6.4.	The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R6.5.	The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010	R7.		Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R7.1.	Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R7.2.	Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R7.3.	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010	R8.		Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R8.1.	A document identifying the vulnerability assessment process;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R8.2.	A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R8.3.	A review of controls for default accounts; and,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-007-3, Effective 10/1/2010		R8.4.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			

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CIP-007-3, Effective 10/1/2010	R9.		Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-3 at least annually.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-008-3, Effective 10/1/2010	R1.		Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan and implement the plan in	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-008-3, Effective 10/1/2010		R1.1.	Procedures to characterize and classify events as reportable Cyber Security Incidents.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-008-3, Effective 10/1/2010		R1.2.	Response actions, including roles and responsibilities of Cyber Security Incident response teams, Cyber Security Incident handling procedures, and communication	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-008-3, Effective 10/1/2010		R1.3.	Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The Responsible Entity must	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-008-3, Effective 10/1/2010		R1.4.	Process for updating the Cyber Security Incident response plan within thirty calendar days of any changes.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-008-3, Effective 10/1/2010		R1.5.	Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-008-3, Effective 10/1/2010		R1.6.	Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the Cyber Security Incident response plan can range from a	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-008-3, Effective 10/1/2010	R2.		Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-009-3, Effective 10/1/2010	R1.		Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-009-3, Effective 10/1/2010		R1.1.	Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-009-3, Effective 10/1/2010		R1.2.	Define the roles and responsibilities of responders.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-009-3, Effective 10/1/2010	R2.		Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-009-3, Effective 10/1/2010	R3.		Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			

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CIP-009-3, Effective 10/1/2010	R4.		Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A				X	*X*			
CIP-009-3, Effective 10/1/2010	R5.		Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	A					*X*			
			COMMUNICATIONS											
COM-001-1.1	R1.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide adequate and reliable telecommunications facilities for	HIGH	BA, RC, TOP	A				X	*X*	*X*		
COM-001-1.1		R1.1.	Internally.	HIGH	BA, RC, TOP	A				X	*X*	*X*		
COM-001-1.1		R1.2.	Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.	HIGH	BA, RC, TOP	A				X	*X*	*X*		
COM-001-1.1		R1.3.	With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.	HIGH	BA, RC, TOP	A				X	*X*	*X*		
COM-001-1.1		R1.4.	Where applicable, these facilities shall be redundant and diversely routed.	HIGH	BA, RC, TOP	A				X	*X*	*X*		
COM-001-1.1	R2.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications	MEDIUM	BA, RC, TOP	A				X			*X*	*X*
COM-001-1.1	R3.		Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a means to coordinate telecommunications among	LOWER	BA, RC, TOP	A				X				
COM-001-1.1	R4.		Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all	MEDIUM	BA, RC, TOP	A				X				
COM-001-1.1	R5.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable	LOWER	BA, RC, TOP	A				X	*X*		*X*	*X*
COM-001-1.1	R6.		Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, "NERCNet Security Policy."	LOWER	NERC_Net Users	A				X	*X*			
COM-002-2	R1.		Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability	HIGH	BA, GOP, TOP	A				X	*X*	*X*	*X*	

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COM-002-2		R1.1.	Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities	HIGH	BA, TOP	A				X	*X*	*X*	*X*	
COM-002-2	R2.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall	MEDIUM	BA, RC, TOP	A				X	*X*		*X*	
			EMERGENCY PREPAREDNESS AND OPERATIONS											
EOP-001-0	R1.		Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for	HIGH	BA						*X*	*X*	*X*	*X*
EOP-001-0	R2.		The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission	MEDIUM	TOP	A				X		*X*	*X*	*X*
EOP-001-0	R3.		Each Transmission Operator and Balancing Authority shall:	MEDIUM	BA, TOP	A				X		*X*	*X*	*X*
EOP-001-0		R3.1.	Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.	MEDIUM	BA, TOP	A				X		*X*	*X*	*X*
EOP-001-0		R3.2.	Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.	MEDIUM	BA, TOP	A				X		*X*	*X*	*X*
EOP-001-0		R3.3.	Develop, maintain, and implement a set of plans for load shedding.	MEDIUM	BA, TOP	A				X		*X*	*X*	*X*
EOP-001-0		R3.4.	Develop, maintain, and implement a set of plans for system restoration.	MEDIUM	BA, TOP							*X*	*X*	*X*
EOP-001-0	R4.		Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a	MEDIUM	BA, TOP							*X*	*X*	*X*
EOP-001-0		R4.1.	Communications protocols to be used during emergencies.	MEDIUM	BA, TOP							*X*	*X*	*X*
EOP-001-0		R4.2.	A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one	MEDIUM	BA, TOP							*X*	*X*	*X*
EOP-001-0		R4.3.	The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.	MEDIUM	BA, TOP							*X*	*X*	*X*

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EOP-001-0		R4.4.	Staffing levels for the emergency.	MEDIUM	BA, TOP							X	X	X
EOP-001-0	R5.		Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency	MEDIUM	BA, TOP	A				X		X	X	X
EOP-001-0	R6.		The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing	MEDIUM	BA, TOP							X	X	X
EOP-001-0	R7.		The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing	MEDIUM	BA, TOP							X	X	X
EOP-001-0		R7.1.	The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.	MEDIUM	BA, TOP							X	X	X
EOP-001-0		R7.2.	The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if	MEDIUM	BA, TOP							X	X	X
EOP-001-0		R7.3.	The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or	MEDIUM	BA, TOP							X	X	X
EOP-001-0		R7.4.	The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal	MEDIUM	BA, TOP							X	X	X
EOP-002-2.1	R1.		Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.	HIGH	BA, RC	A					X	X	X	
EOP-002-2.1	R2.		Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected	HIGH	BA						X	X	X	
EOP-002-2.1	R3.		A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to	HIGH	BA						X	X	X	
EOP-002-2.1	R4.		A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available	HIGH	BA						X	X	X	
EOP-002-2.1	R5.		A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective	HIGH	BA						X	X	X	

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EOP-002-2.1	R6.		If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to	HIGH	BA						X	X	X	
EOP-002-2.1		R6.1.	Loading all available generating capacity.	HIGH	BA						X	X	X	
EOP-002-2.1		R6.2.	Deploying all available operating reserve.	HIGH	BA						X	X	X	
EOP-002-2.1		R6.3.	Interrupting interruptible load and exports.	HIGH	BA						X	X	X	
EOP-002-2.1		R6.4.	Requesting emergency assistance from other Balancing Authorities.	HIGH	BA						X	X	X	
EOP-002-2.1		R6.5.	Declaring an Energy Emergency through its Reliability Coordinator; and	HIGH	BA						X	X	X	
EOP-002-2.1		R6.6.	Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.	HIGH	BA						X	X	X	
EOP-002-2.1	R7.		Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:	HIGH	BA	A				X	X	X	X	
EOP-002-2.1		R7.1.	Manually shed firm load without delay to return its ACE to zero; and	HIGH	BA	A				X	X	X	X	
EOP-002-2.1		R7.2.	Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency Alert Levels."	HIGH	BA	A				X	X	X	X	
EOP-002-2.1	R8.		A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in	HIGH	RC	A				X	X	X	X	
EOP-002-2.1	R9.		When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network	HIGH	LSE, RC						X	X	X	
EOP-002-2.1		R9.1.	The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-	HIGH	LSE						X	X	X	
EOP-002-2.1		R9.2.	The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission	HIGH	RC			ER			X	X	X	

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EOP-002-2.1		R9.3.	The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6	LOWER	RC			ER					X	
EOP-002-2.1		R9.4.	The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6	LOWER	RC			ER					X	
EOP-003-1	R1.		After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall	HIGH	BA, TOP						X	X	X	X
EOP-003-1	R2.		Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage	HIGH	BA, TOP	A				X	X	X	X	X
EOP-003-1	R3.		Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators	HIGH	BA, TOP	A				X	X	X	X	X
EOP-003-1	R4.		A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of	HIGH	BA, TOP	A				X	X	X	X	X
EOP-003-1	R5.		A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of	HIGH	BA, TOP						X	X	X	X
EOP-003-1	R6.		After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system	HIGH	BA, TOP						X	X	X	X
EOP-003-1	R7.		The Transmission Operator and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of	HIGH	BA, TOP						X	X	X	X
EOP-003-1	R8.		Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The	HIGH	BA, TOP	A				X	X	X	X	X
EOP-004-1	R1.		Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final	LOWER	RRO								X	
EOP-004-1	R2.		A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall promptly analyze Bulk	MEDIUM	BA, GOP, LSE, RC, TOP								X	
EOP-004-1	R3.		A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity experiencing a reportable incident	LOWER	BA, GOP, LSE, RC, TOP			ER					X	
EOP-004-1		R3.1.	The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall submit within 24	LOWER	BA, GOP, LSE, RC, TOP			ER					X	

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EOP-004-1		R3.2.	Applicable reporting forms are provided in Attachments 022-1 and 022-2.	No VRF Assigned	BA, GOP, LSE, RC, TOP								*X*	
EOP-004-1		R3.3.	Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written	LOWER	BA, GOP, LSE, RC, TOP			ER					*X*	
EOP-004-1		R3.4.	If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission	LOWER	BA, GOP, LSE, RC, TOP								*X*	
EOP-004-1	R4.		When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating	LOWER	RRO			ER					*X*	
EOP-004-1	R5.		The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being	LOWER	RRO			ER					*X*	
EOP-005-1	R1.		Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of	MEDIUM	TOP	A				X	*X*	*X*	*X*	*X*
EOP-005-1	R2.		Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall	MEDIUM	TOP	A				X	*X*	*X*	*X*	*X*
EOP-005-1	R3.		Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.	MEDIUM	TOP	A				X	*X*	*X*	*X*	*X*
EOP-005-1	R4.		Each Transmission Operator shall coordinate its restoration plans with the Generator Owners and Balancing Authorities within its area, its Reliability	MEDIUM	TOP	A				X	*X*	*X*	*X*	*X*
EOP-005-1	R5.		Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.	MEDIUM	BA, TOP	A				X	*X*	*X*	*X*	*X*
EOP-005-1	R6.		Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan.	HIGH	BA, TOP	A				X	*X*	*X*	*X*	*X*
EOP-005-1	R7.		Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.	HIGH	BA, TOP	A				X	*X*	*X*	*X*	*X*
EOP-005-1	R8.		Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional	HIGH	TOP							*X*	*X*	*X*
EOP-005-1	R9.		The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the	MEDIUM	TOP	A				X	*X*	*X*	*X*	*X*

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EOP-005-1	R10.		The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform	MEDIUM	TOP	A				X		*X*	*X*	*X*
EOP-005-1		R10.1.	The Transmission Operator shall perform this simulation or testing at least once every five years.	MEDIUM	TOP	A				X		*X*	*X*	*X*
EOP-005-1	R11.		Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and	HIGH	BA, TOP						*X*	*X*	*X*	*X*
EOP-005-1		R11.1.	The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent	MEDIUM	BA, TOP							*X*	*X*	*X*
EOP-005-1		R11.2.	The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including	HIGH	BA, TOP						*X*	*X*	*X*	*X*
EOP-005-1		R11.3.	The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those	HIGH	BA						*X*	*X*	*X*	*X*
EOP-005-1		R11.4.	The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.	HIGH	TOP						*X*	*X*	*X*	*X*
EOP-005-1		R11.5.	The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:	MEDIUM	TOP								*X*	*X*
EOP-005-1		R11.5.1.	Voltage, frequency, and phase angle permit.	HIGH	TOP						*X*	*X*	*X*	*X*
EOP-005-1		R11.5.2.	The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across	HIGH	TOP						*X*	*X*	*X*	*X*
EOP-005-1		R11.5.3.	Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.	MEDIUM	TOP								*X*	*X*
EOP-005-1		R11.5.4.	Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.	HIGH	TOP						*X*	*X*	*X*	*X*
EOP-006-1	R1.		Each Reliability Coordinator shall be aware of the restoration plan of each Transmission Operator in its Reliability Coordinator Area in accordance with	MEDIUM	RC	A							*X*	*X*
EOP-006-1	R2.		The Reliability Coordinator shall monitor restoration progress and coordinate any needed assistance.	HIGH	RC						*X*	*X*	*X*	*X*

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EOP-006-1	R3.		The Reliability Coordinator shall have a Reliability Coordinator Area restoration plan that provides coordination between individual Transmission Operator	MEDIUM	RC	A							*X*	*X*
EOP-006-1	R4.		The Reliability Coordinator shall serve as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and	MEDIUM	RC								*X*	*X*
EOP-006-1	R5.		Reliability Coordinators shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to cause a	HIGH	RC						*X*	*X*	*X*	*X*
EOP-006-1	R6.		The Reliability Coordinator shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its	MEDIUM	RC								*X*	*X*
EOP-008-0	R1.		Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its	HIGH	BA, RC, TOP	A				X	*X*	*X*	*X*	*X*
EOP-008-0		R1.1.	The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.	MEDIUM	BA, RC, TOP	A				X	*X*	*X*	*X*	*X*
EOP-008-0		R1.2.	The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area	MEDIUM	BA, RC, TOP	A				X	*X*	*X*	*X*	*X*
EOP-008-0		R1.3.	The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and	MEDIUM	BA, RC, TOP	A				X	*X*	*X*	*X*	*X*
EOP-008-0		R1.4.	The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.	HIGH	BA, RC, TOP	A				X	*X*	*X*	*X*	*X*
EOP-008-0		R1.5.	The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.	MEDIUM	BA, RC, TOP	A				X	*X*	*X*	*X*	*X*
EOP-008-0		R1.6.	The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the	MEDIUM	BA, RC, TOP	A				X	*X*	*X*	*X*	*X*
EOP-008-0		R1.7.	The plan shall be reviewed and updated annually.	MEDIUM	BA, RC, TOP	A				X	*X*	*X*	*X*	*X*
EOP-008-0		R1.8.	Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.	MEDIUM	BA, RC, TOP	A				X	*X*	*X*	*X*	*X*
EOP-009-0	R1.		The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the	MEDIUM	GOP								*X*	*X*

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EOP-009-0	R2.		The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating	LOWER	GO, GOP		A						X	X
			FACILITIES DESIGN, CONNECTIONS AND MAINTENANCE											
FAC-001-0	R1.		The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and	MEDIUM	TO	A					X	X		
FAC-001-0		R1.1.	Generation facilities,	MEDIUM	TO	A					X	X		
FAC-001-0		R1.2.	Transmission facilities, and	MEDIUM	TO	A					X	X		
FAC-001-0		R1.3.	End-user facilities	MEDIUM	TO	A					X	X		
FAC-001-0	R2.		The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.1.	Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.2.	Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.3.	Voltage level and MW and MVAR capacity or demand at point of connection.	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.4.	Breaker duty and surge protection.	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.5.	System protection and coordination.	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.6.	Metering and telecommunications.	MEDIUM	TO	A					X	X		

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FAC-001-0		R2.1.7.	Grounding and safety issues.	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.8.	Insulation and insulation coordination.	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.9.	Voltage, Reactive Power, and power factor control.	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.10.	Power quality impacts.	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.11.	Equipment Ratings.	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.12.	Synchronizing of facilities.	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.13.	Maintenance coordination.	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.14.	Operational issues (abnormal frequency and voltages).	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.15.	Inspection requirements for existing or new facilities.	MEDIUM	TO	A					X	X		
FAC-001-0		R2.1.16.	Communications and procedures during normal and emergency operating conditions.	MEDIUM	TO	A					X	X		
FAC-001-0	R3.		The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make	MEDIUM	TO	A					X	X		
FAC-002-0	R1.		The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission	MEDIUM	DP, GO, LSE, TO									
FAC-002-0		R1.1.	Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.	MEDIUM	DP, GO, LSE, TO									
FAC-002-0		R1.2.	Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and	MEDIUM	DP, GO, LSE, TO									

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FAC-002-0		R1.3.	Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the	MEDIUM	DP, GO, LSE, TO									
FAC-002-0		R1.4.	Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with	MEDIUM	DP, GO, LSE, TO						*X*			
FAC-002-0		R1.5.	Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated	MEDIUM	DP, GO, LSE, TO						*X*			
FAC-002-0	R2.		The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its	LOWER	DP, GO, LSE, PA, PC, TO, TP									
FAC-003-1	R1.		The Transmission owner shall prepare, and keep current, a formal transmission vegetation management (TVM). The TVMP shall include the Transmission Owner's	HIGH	TO	A				X	*X*	*X*	*X*	*X*
FAC-003-1		R1.1.	The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for	HIGH	TO	A				X	*X*	*X*	*X*	*X*
FAC-003-1		R1.2.	The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking	HIGH	TO	A				X	*X*	*X*	*X*	*X*
FAC-003-1		R1.2.1.	Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission	HIGH	TO	A				X	*X*	*X*	*X*	*X*
FAC-003-1		R1.2.2.	Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors	HIGH	TO	A				X	*X*	*X*	*X*	*X*
FAC-003-1		R1.2.2.1.	Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground	HIGH	TO	A				X	*X*	*X*	*X*	*X*
FAC-003-1		R1.2.2.2.	Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages,	HIGH	TO	A				X	*X*	*X*	*X*	*X*
FAC-003-1		R1.3.	All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission	HIGH	TO	A				X	*X*	*X*	*X*	*X*
FAC-003-1		R1.4.	Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies	HIGH	TO	A				X	*X*	*X*	*X*	*X*
FAC-003-1		R1.5.	Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent	HIGH	TO	A				X	*X*	*X*	*X*	*X*

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FAC-003-1	R2.		The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe	HIGH	TO	A				X	*X*	*X*	*X*	*X*
FAC-003-1	R3.		The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission	LOWER	TO		Q						*X*	*X*
FAC-003-1		R3.1.	Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of	LOWER	TO		Q						*X*	*X*
FAC-003-1		R3.2.	The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1)	LOWER	TO		Q						*X*	*X*
FAC-003-1		R3.3.	The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s)	LOWER	TO		Q						*X*	*X*
FAC-003-1		R3.4.	An outage shall be categorized as one of the following:	LOWER	TO		Q						*X*	*X*
FAC-003-1		R3.4.1.	Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW.	LOWER	TO		Q						*X*	*X*
FAC-003-1		R3.4.2.	Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW.	LOWER	TO		Q						*X*	*X*
FAC-003-1		R3.4.3.	Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.	LOWER	TO		Q						*X*	*X*
FAC-003-1	R4.		The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well	LOWER	RRO		Q						*X*	*X*
FAC-008-1	R1.		The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of	LOWER	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-008-1		R1.1.	A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.	MEDIUM	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-008-1		R1.2.	The method by which the Rating (of major BES equipment that comprises a Facility) is determined.	MEDIUM	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-008-1		R1.2.1.	The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal	MEDIUM	GO, TO	A				X	*X*	*X*	*X*	*X*

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FAC-008-1		R1.2.2.	The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.	MEDIUM	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-008-1		R1.3.	Consideration of the following:	LOWER	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-008-1		R1.3.1.	Ratings provided by equipment manufacturers.	MEDIUM	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-008-1		R1.3.2.	Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).	MEDIUM	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-008-1		R1.3.3.	Ambient conditions.	MEDIUM	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-008-1		R1.3.4.	Operating limitations.	MEDIUM	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-008-1		R1.3.5.	Other assumptions.	LOWER	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-008-1	R2.		The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those	LOWER	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-008-1	R3.		If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a	LOWER	GO, TO						*X*	*X*	*X*	*X*
FAC-009-1	R1.		The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the	MEDIUM	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-009-1	R2.		The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities,	MEDIUM	GO, TO	A				X	*X*	*X*	*X*	*X*
FAC-010-2.1 Effective 4/19/2010	R1.		The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology	LOWER	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R1.1.	Be applicable for developing SOLs used in the planning horizon.	LOWER	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R1.2.	State that SOLs shall not exceed associated Facility Ratings.	LOWER	PA, PC									

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FAC-010-2.1 Effective 4/19/2010		R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	LOWER	PA, PC									
FAC-010-2.1 Effective 4/19/2010	R2.		The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	No VRF Assigned	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R2.1.	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within	HIGH	PA, PC						*X*	*X*		
FAC-010-2.1 Effective 4/19/2010		R2.2.	Following the single Contingencies1 identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and	HIGH	PA, PC						*X*	*X*		
FAC-010-2.1 Effective 4/19/2010		R2.2.1.	Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	MEDIUM	PA, PC						*X*	*X*		
FAC-010-2.1 Effective 4/19/2010		R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	MEDIUM	PA, PC						*X*	*X*		
FAC-010-2.1 Effective 4/19/2010		R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	MEDIUM	PA, PC						*X*	*X*		
FAC-010-2.1 Effective 4/19/2010		R2.3.	Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	MEDIUM	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by	MEDIUM	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R2.3.2.	System reconfiguration through manual or automatic control or protection actions.	MEDIUM	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R2.4.	To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the	MEDIUM	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R2.5.	Starting with all facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall	MEDIUM	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R2.6.	In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in	MEDIUM	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R2.6.1.	Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the	MEDIUM	PA, PC									

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FAC-010-2.1 Effective 4/19/2010	R3.		The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied	LOWER	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R3.1.	Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would	LOWER	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R3.2.	Selection of applicable Contingencies.	LOWER	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R3.3.	Level of detail of system models used to determine SOLs.	LOWER	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R3.4.	Allowed uses of Special Protection Systems or Remedial Action Plans.	MEDIUM	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R3.5.	Anticipated transmission system configuration, generation dispatch and Load level.	LOWER	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated	MEDIUM	PA, PC									
FAC-010-2.1 Effective 4/19/2010	R4.		The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:	LOWER	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	LOWER	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	LOWER	PA, PC									
FAC-010-2.1 Effective 4/19/2010		R4.3.	Each Transmission Planner that works in the Planning Authority's Planning Authority Area.	LOWER	PA, PC									
FAC-010-2.1 Effective 4/19/2010	R5.		If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a	LOWER	PA, PC									
FAC-011-2 Effective 4/29/2009	R1.		The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.	LOWER	RC									
FAC-011-2 Effective 4/29/2009		R1.1.	Be applicable for developing SOLs used in the operations horizon.	LOWER	RC									

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FAC-011-2 Effective 4/29/2009		R1.2.	State that SOLs shall not exceed associated Facility Ratings.	LOWER	RC									
FAC-011-2 Effective 4/29/2009		R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	LOWER	RC									
FAC-011-2 Effective 4/29/2009	R2.		The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	No VRF Assigned	RC									
FAC-011-2 Effective 4/29/2009		R2.1.	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within	HIGH	RC						*X*	*X*		
FAC-011-2 Effective 4/29/2009		R2.2.	Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and	HIGH	RC						*X*	*X*		
FAC-011-2 Effective 4/29/2009		R2.2.1.	Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	MEDIUM	RC						*X*	*X*		
FAC-011-2 Effective 4/29/2009		R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	MEDIUM	RC						*X*	*X*		
FAC-011-2 Effective 4/29/2009		R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	MEDIUM	RC						*X*	*X*		
FAC-011-2 Effective 4/29/2009		R2.3.	In determining the system's response to a single Contingency, the following shall be acceptable:	MEDIUM	RC									
FAC-011-2 Effective 4/29/2009		R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by	MEDIUM	RC									
FAC-011-2 Effective 4/29/2009		R2.3.2.	Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-	MEDIUM	RC									
FAC-011-2 Effective 4/29/2009		R2.3.3.	System reconfiguration through manual or automatic control or protection actions.	MEDIUM	RC									
FAC-011-2 Effective 4/29/2009		R2.4.	To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the	MEDIUM	RC									
FAC-011-2 Effective 4/29/2009	R3.		The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability	MEDIUM	RC									

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FAC-011-2 Effective 4/29/2009		R3.1.	Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would	MEDIUM	RC									
FAC-011-2 Effective 4/29/2009		R3.2.	Selection of applicable Contingencies	MEDIUM	RC									
FAC-011-2 Effective 4/29/2009		R3.3.	A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with	MEDIUM	RC									
FAC-011-2 Effective 4/29/2009		R3.3.1.	This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies	No VRF Assigned	RC									
FAC-011-2 Effective 4/29/2009		R3.4.	Level of detail of system models used to determine SOLs.	LOWER	RC									
FAC-011-2 Effective 4/29/2009		R3.5.	Allowed uses of Special Protection Systems or Remedial Action Plans.	MEDIUM	RC									
FAC-011-2 Effective 4/29/2009		R3.6.	Anticipated transmission system configuration, generation dispatch and Load level	MEDIUM	RC									
FAC-011-2 Effective 4/29/2009		R3.7.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated	MEDIUM	RC									
FAC-011-2 Effective 4/29/2009	R4.		The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a	LOWER	RC									
FAC-011-2 Effective 4/29/2009		R4.1.	Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	LOWER	RC									
FAC-011-2 Effective 4/29/2009		R4.2.	Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	LOWER	RC									
FAC-011-2 Effective 4/29/2009		R4.3.	Each Transmission Operator that operates in the Reliability Coordinator Area.	LOWER	RC									
FAC-011-2 Effective 4/29/2009	R5.		If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a	LOWER	RC									
FAC-013-1	R1.		The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its	MEDIUM	PA, PC, RC								X	

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FAC-013-1	R2.		The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a	MEDIUM	PA, PC, RC								X	
FAC-013-1		R2.1.	The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to	MEDIUM	RC								X	
FAC-013-1		R2.2.	The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the	MEDIUM	PA, PC								X	
FAC-014-2	R1.		The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are	MEDIUM	RC	A								
FAC-014-2	R2.		The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are	MEDIUM	RC, TOP	A								
FAC-014-2	R3.		The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.	MEDIUM	PA, PC	A								
FAC-014-2	R4.		The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's	MEDIUM	PA, PC, TP	A								
FAC-014-2	R5.		The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need	HIGH	PA, PC, RC, TP	A					X	X		
FAC-014-2		R5.1.	The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators	HIGH	RC	A					X	X		
FAC-014-2		R5.1.1.	Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.	MEDIUM	RC	A					X	X		
FAC-014-2		R5.1.2.	The value of the IROL and its associated Tv.	MEDIUM	RC	A					X	X		
FAC-014-2		R5.1.3.	The associated Contingency(ies).	MEDIUM	RC	A					X	X		
FAC-014-2		R5.1.4.	The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	MEDIUM	RC	A					X	X		
FAC-014-2		R5.2.	The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of	MEDIUM	TOP	A								

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FAC-014-2		R5.3.	The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission	MEDIUM	PA, PC	A								
FAC-014-2		R5.4.	The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission	MEDIUM	TP	A								
FAC-014-2	R6.		The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.	MEDIUM	PA, PC									
FAC-014-2		R6.1.	The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the	MEDIUM	PA, PC									
FAC-014-2		R6.2.	If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	MEDIUM	PA, PC									
			INTERCHANGE SCHEDULING AND COORDINATION											
INT-001-3	R1.		The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:	LOWER	PSE			ER						
INT-001-3		R1.1.	All Dynamic Schedules at the expected average MW profile for each hour.	LOWER	PSE			ER						
INT-001-3	R2.		The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:	LOWER	BA			ER						
INT-001-3		R2.1.	If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.	LOWER	BA			ER						
INT-001-3		R2.2.	For each bilateral Inadvertent Interchange payback.	LOWER	BA			ER						
INT-003-2	R1.		Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing	MEDIUM	BA			ER					X	
INT-003-2		R1.1.	The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including:	LOWER	BA			ER					X	
INT-003-2		R1.1.1.	Interchange Schedule start and end time.	LOWER	BA			ER					X	

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INT-003-2		R1.1.2.	Energy profile.	LOWER	BA			ER					X	
INT-003-2		R1.2.	If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall	MEDIUM	BA			ER					X	
INT-004-2	R1.		At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange	LOWER	BA, PSE, RC, TOP									
INT-004-2	R2.		The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and	LOWER	PSE									
INT-004-2		R2.1.	The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile	LOWER	PSE									
INT-004-2		R2.2.	The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy	LOWER	PSE									
INT-004-2		R2.3.	A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-	LOWER	PSE									
INT-005-3 Effective 7/1/2010	R1.		Prior to the expiration of the time period defined in the Timing Table, Column A, the Interchange Authority shall distribute the Arranged Interchange information for	MEDIUM	IA									
INT-005-3 Effective 7/1/2010		R1.1.	When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority	MEDIUM	IA									
INT-006-3 Effective 7/1/2010	R1.		Prior to the expiration of the reliability assessment period defined in the Timing Table, Column B, the Balancing Authority and Transmission Service Provider shall	LOWER	BA, TSP									
INT-006-3 Effective 7/1/2010		R1.1.	Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:	LOWER	BA									
INT-006-3 Effective 7/1/2010		R1.1.1.	Energy profile (ability to support the magnitude of the Interchange).	LOWER	BA									
INT-006-3 Effective 7/1/2010		R1.1.2.	Ramp (ability of generation maneuverability to accommodate).	LOWER	BA									
INT-006-3 Effective 7/1/2010		R1.1.3.	Scheduling path (proper connectivity of Adjacent Balancing Authorities).	LOWER	BA									

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INT-006-3 Effective 7/1/2010		R1.2.	Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange	LOWER	TSP									
INT-007-1	R1.		The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by	LOWER	IA									
INT-007-1		R1.1.	Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).	LOWER	IA									
INT-007-1		R1.2.	All reliability entities involved in the Arranged Interchange are currently in the NERC registry.	LOWER	IA									
INT-007-1		R1.3.	The following are defined:	LOWER	IA									
INT-007-1		R1.3.1.	Generation source and load sink.	LOWER	IA									
INT-007-1		R1.3.2.	Megawatt profile.	LOWER	IA									
INT-007-1		R1.3.3.	Ramp start and stop times.	LOWER	IA									
INT-007-1		R1.3.4.	Interchange duration.	LOWER	IA									
INT-007-1		R1.4.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange	LOWER	IA									
INT-008-3 Effective 7/1/2010	R1.		Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including	LOWER	IA									
INT-008-3 Effective 7/1/2010		R1.1.	For Confirmed Interchange, the Interchange Authority shall also communicate:	LOWER	IA									
INT-008-3 Effective 7/1/2010		R1.1.1.	Start and stop times, ramps, and megawatt profile to Balancing Authorities.	LOWER	IA									
INT-008-3 Effective 7/1/2010		R1.1.2.	Necessary Interchange information to NERC-identified reliability analysis services.	LOWER	IA									

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INT-009-1	R1.		The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.	MEDIUM	BA									
INT-010-1	R1.		The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is	LOWER	BA									
INT-010-1	R2.		For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the	LOWER	RC									
INT-010-1	R3.		For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall	LOWER	RC									
			INTERCONNECTION RELIABILITY OPERATIONS AND COORDINATION											
IRO-001-1.1	R1.		Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously	HIGH	RRO								*X*	*X*
IRO-001-1.1	R2.		The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	HIGH	RC							*X*	*X*	*X*
IRO-001-1.1	R3.		The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing	HIGH	RC						*X*	*X*	*X*	*X*
IRO-001-1.1	R4.		Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability	MEDIUM	RC							*X*	*X*	*X*
IRO-001-1.1	R5.		The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	LOWER	RC							*X*	*X*	*X*
IRO-001-1.1	R6.		The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	MEDIUM	RC							*X*	*X*	*X*
IRO-001-1.1	R7.		The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System	HIGH	RC						*X*	*X*	*X*	*X*
IRO-001-1.1	R8.		Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling	HIGH	BA, GOP, LSE, PSE, TOP, TSP						*X*	*X*	*X*	*X*
IRO-001-1.1	R9.		The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of	HIGH	RC						*X*	*X*	*X*	*X*

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IRO-002-1	R1.		Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator	HIGH	RC						*X*	*X*		
IRO-002-1	R2.		Each Reliability Coordinator shall determine the data requirements to support its reliability coordination tasks and shall request such data from its	MEDIUM	RC									
IRO-002-1	R3.		Each Reliability Coordinator – or its Transmission Operators and Balancing Authorities – shall provide, or arrange provisions for, data exchange to other	MEDIUM	BA, RC, TOP									
IRO-002-1	R4.		Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and	HIGH	RC						*X*	*X*		
IRO-002-1	R5.		Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its	HIGH	RC	A					*X*	*X*		
IRO-002-1	R6.		Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could	HIGH	RC	A					*X*	*X*		
IRO-002-1	R7.		Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability,	HIGH	RC	A					*X*	*X*		
IRO-002-1	R8.		Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for	HIGH	RC	A					*X*	*X*		
IRO-002-1	R9.		Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability	MEDIUM	RC	A								
IRO-003-2	R1.		Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability	HIGH	RC	A					*X*	*X*	*X*	
IRO-003-2	R2.		Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or	HIGH	RC	A					*X*	*X*	*X*	
IRO-004-1	R1.		Each Reliability Coordinator shall conduct next-day reliability analyses for its Reliability Coordinator Area to ensure that the Bulk Electric System can be	HIGH	RC	A		ER		X	*X*	*X*	*X*	*X*
IRO-004-1	R2.		Each Reliability Coordinator shall pay particular attention to parallel flows to ensure one Reliability Coordinator Area does not place an unacceptable or undue	HIGH	RC	A				X	*X*	*X*	*X*	*X*
IRO-004-1	R3.		Each Reliability Coordinator shall, in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be	HIGH	RC	A				X	*X*	*X*	*X*	*X*

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IRO-004-1	R4.		Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity in the Reliability	HIGH	BA, GO, GOP, LSE, TO, TOP	A		ER		X	*X*	*X*	*X*	*X*
IRO-004-1	R5.		Each Reliability Coordinator shall share the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with	HIGH	RC	A		ER		X	*X*	*X*	*X*	*X*
IRO-004-1	R6.		If the results of these studies indicate potential SOL or IROL violations, the Reliability Coordinator shall direct its Transmission Operators, Balancing	HIGH	RC	A				X	*X*	*X*	*X*	*X*
IRO-004-1	R7.		Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the	HIGH	BA, TOP, TSP	A				X	*X*	*X*	*X*	*X*
IRO-005-2	R1.		Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2		R1.1.	Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2		R1.2.	Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations,	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2		R1.3.	Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations,	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2		R1.4.	System real and reactive reserves (actual versus required).	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2		R1.5.	Capacity and energy adequacy conditions.	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2		R1.6.	Current ACE for all its Balancing Authorities.	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2		R1.7.	Current local or Transmission Loading Relief procedures in effect.	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2		R1.8.	Planned generation dispatches.	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2		R1.9.	Planned transmission or generation outages.	HIGH	RC	A				X	*X*	*X*	*X*	

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IRO-005-2		R1.10.	Contingency events.	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2	R2.		Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2	R3.		As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2	R4.		Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2	R5.		Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2	R6.		Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast	HIGH	RC	A				X				
IRO-005-2	R7.		The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2	R8.		Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS	HIGH	BA, RC, TOP	A				X	*X*	*X*	*X*	
IRO-005-2	R9.		The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2	R10.		As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2	R11.		The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange	HIGH	RC	A				X	*X*	*X*	*X*	
IRO-005-2	R12.		Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect	HIGH	RC, TOP	A				X	*X*	*X*	*X*	
IRO-005-2	R13.		Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service	HIGH	BA, GOP, LSE, PSE, RC, TOP, TSP	A				X	*X*	*X*	*X*	
IRO-005-2	R14.		Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view.	MEDIUM	RC, TSP	A				X	*X*		*X*	

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IRO-005-2	R15.		Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability	HIGH	RC	A				X	X	X	X	
IRO-005-2	R16.		Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas.	HIGH	RC	A				X	X	X	X	
IRO-005-2	R17.		When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and	HIGH	RC	A				X	X	X	X	
IRO-006-4.1	R1.		A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, with its authority and at its	MEDIUM	RC			ER			X	X	X	
IRO-006-4.1		R1.1.	The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection provided in Attachment 1-IRO-006-4. The TLR	Part of Main Requirement	RC						X	X	X	
IRO-006-4.1		R1.2.	The Interconnection-wide transmission loading relief procedure for use in the Western Interconnection is WECC-IRO-STD-006-0 provided at:	Part of Main Requirement	RC								X	
IRO-006-4.1		R1.3.	The Interconnection-wide transmission loading relief procedure for use in ERCOT is provided as Section 7 of the ERCOT Protocols, posted at:	Part of Main Requirement	RC								X	
IRO-006-4.1	R2.		The Reliability Coordinator shall only use local transmission loading relief or congestion management procedures to which the Transmission Operator	LOWER	RC			ER					X	
IRO-006-4.1	R3.		Each Reliability Coordinator with a relief obligation from an Interconnection-wide procedure shall follow the curtailments as directed by the Interconnection-wide	LOWER	RC			ER			X	X	X	
IRO-006-4.1	R4.		When Interconnection-wide procedures are implemented to curtail Interchange Transactions that cross an Interconnection boundary, each	MEDIUM	RC			ER			X	X	X	
IRO-006-4.1	R5.		During the implementation of relief procedures, and up to the point that emergency action is necessary, Reliability Coordinators and Balancing	MEDIUM	RC, BA			ER			X	X	X	
IRO-014-1	R1.		The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or	MEDIUM	RC								X	X
IRO-014-1		R1.1.	These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:	LOWER	RC								X	X
IRO-014-1		R1.1.1.	Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to	MEDIUM	RC								X	X

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IRO-014-1		R1.1.2.	Energy and capacity shortages.	MEDIUM	RC								X	X
IRO-014-1		R1.1.3.	Planned or unplanned outage information.	MEDIUM	RC								X	X
IRO-014-1		R1.1.4.	Voltage control, including the coordination of reactive resources for voltage control.	MEDIUM	RC								X	X
IRO-014-1		R1.1.5.	Coordination of information exchange to support reliability assessments.	LOWER	RC								X	X
IRO-014-1		R1.1.6.	Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	LOWER	RC								X	X
IRO-014-1	R2.		Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make	LOWER	RC								X	X
IRO-014-1		R2.1.	Agreed to by all the Reliability Coordinators required to take the indicated action(s).	LOWER	RC								X	X
IRO-014-1		R2.2.	Distributed to all Reliability Coordinators that are required to take the indicated action(s).	LOWER	RC								X	X
IRO-014-1	R3.		A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator	MEDIUM	RC								X	X
IRO-014-1		R3.1.	A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	MEDIUM	RC								X	X
IRO-014-1		R3.2.	The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	LOWER	RC								X	X
IRO-014-1	R4.		Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:	LOWER	RC								X	X
IRO-014-1		R4.1.	Include version control number or date	LOWER	RC								X	X
IRO-014-1		R4.2.	Include a distribution list.	LOWER	RC								X	X

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IRO-014-1		R4.3.	Be reviewed, at least once every three years, and updated if needed.	LOWER	RC								X	X
IRO-015-1	R1.		The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information	MEDIUM	RC								X	X
IRO-015-1		R1.1.	The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may	MEDIUM	RC								X	X
IRO-015-1	R2.		The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.	LOWER	RC								X	X
IRO-015-1		R2.1.	The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	LOWER	RC								X	X
IRO-015-1	R3.		The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.	MEDIUM	RC								X	X
IRO-016-1	R1.		The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall	MEDIUM	RC								X	X
IRO-016-1		R1.1.	If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability	MEDIUM	RC								X	X
IRO-016-1		R1.2.	If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data,	MEDIUM	RC								X	X
IRO-016-1		R1.2.1.	If time permits, this re-evaluation shall be done before taking corrective actions.	MEDIUM	RC								X	X
IRO-016-1		R1.2.2.	If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.	MEDIUM	RC								X	X
IRO-016-1		R1.3.	If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	MEDIUM	RC								X	X
IRO-016-1	R2.		The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the	LOWER	RC								X	X
			MODELING, DATA AND ANALYSIS											

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MOD-001-1 Auditable 6/1/2011	R1.		Each Transmission Operator shall select one of the methodologies1 listed below for calculating Available Transfer Capability	Pending	TOP	A				X				
MOD-001-1 Auditable 6/1/2011	R2.		Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R2.1.	Hourly values for at least the next 48 hours.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R2.2.	Daily values for at least the next 31 calendar days.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R2.3.	Monthly values for at least the next 12 months (months 2-13).	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011	R3.		Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R3.1.	Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R3.2.	A description of the manner in which the Transmission Service Provider will account for counterflows including:	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R3.2.1.	How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R3.2.2.	A rationale for that accounting specified in R3.2.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R3.3.	The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R3.4.	The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R3.5.	A description of the allocation processes listed below that are applicable to the Transmission Service Provider: a) Processes used to allocate transfer or	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R3.6.	A description of how generation and transmission outages are considered in transfer or Flowgate capability calculations, including:	Pending	TSP	A				X				

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MOD-001-1 Auditable 6/1/2011		R3.6.1.	The criteria used to determine when an outage that is in effect part of a day impacts a daily calculation.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R3.6.2.	The criteria used to determine when an outage that is in effect part of a month impacts a monthly calculation.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R3.6.3.	How outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011	R4.		The Transmission Service Provider shall notify the following entities before implementing a new or revised ATCID:	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R4.1.	Each Planning Coordinator associated with the Transmission Service Provider's area.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R4.2.	Each Reliability Coordinator associated with the Transmission Service Provider's area.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R4.3.	Each Transmission Operator associated with the Transmission Service Provider's area.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R4.4.	Each Planning Coordinator adjacent to the Transmission Service Provider's area.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R4.5.	Each Reliability Coordinator adjacent to the Transmission Service Provider's area	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R4.6.	Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011	R5.		The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011	R6.		When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more	Pending	TOP	A				X				
MOD-001-1 Auditable 6/1/2011	R7.		When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011	R8.		Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values	Pending	TSP	A				X				

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MOD-001-1 Auditable 6/1/2011		R8.1.	Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R8.2.	Daily values, once per day	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R8.3.	Monthly values, once per week.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011	R9.		Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R9.1.	Transmission Service.	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R9.1.1.	If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R9.1.2.	If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R9.1.3.	If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that	Pending	TSP	A				X				
MOD-001-1 Auditable 6/1/2011		R9.2.	This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless	Pending	TSP	A				X				
MOD-004-1 Auditable 6/1/2011	R1.		The Transmission Service Provider that maintains CBM shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that	Pending	TSP	A				X				
MOD-004-1 Auditable 6/1/2011		R1.1.	The process through which a Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the	Pending	TSP	A				X				
MOD-004-1 Auditable 6/1/2011		R1.2.	The procedure and assumptions for establishing CBM for each Available Transfer Capability (ATC) Path or Flowgate.	Pending	TSP	A				X				
MOD-004-1 Auditable 6/1/2011		R1.3.	The procedure for a Load-Serving Entity or Balancing Authority to use Transmission capacity set aside as CBM, including the manner in which the	Pending	TSP	A				X				
MOD-004-1 Auditable 6/1/2011	R2.		The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service	Pending	TSP	A				X				

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MOD-004-1 Auditable 6/1/2011	R3.		Each Load-Serving Entity determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine	Pending	LSE	A				X				
MOD-004-1 Auditable 6/1/2011		R3.1.	Using one or more of the following to determine the GCIR: a) Loss of Load Expectation (LOLE) studies	Pending	LSE	A				X				
MOD-004-1 Auditable 6/1/2011		R3.2.	Identifying expected import path(s) or source region(s).	Pending	LSE	A				X				
MOD-004-1 Auditable 6/1/2011	R4.		Each Resource Planner determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine	Pending	RP	A				X				
MOD-004-1 Auditable 6/1/2011		R4.1.	Using one or more of the following to determine the GCIR: a) Loss of Load Expectation (LOLE) studies	Pending	RP	A				X				
MOD-004-1 Auditable 6/1/2011		R4.2.	Identifying expected import path(s) or source region(s).	Pending	RP	A				X				
MOD-004-1 Auditable 6/1/2011	R5.		At least every 13 months, the Transmission Service Provider that maintains CBM shall establish a CBM value for each ATC Path or Flowgate to be	Pending	TSP	A				X				
MOD-004-1 Auditable 6/1/2011		R5.1.	Reflect consideration of each of the following if available: a) Any studies (as described in R3.1) performed by Load-Serving Entities for	Pending	TSP	A				X				
MOD-004-1 Auditable 6/1/2011		R5.2.	Be allocated as follows: a) For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource	Pending	TSP	A				X				
MOD-004-1 Auditable 6/1/2011	R6.		At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used in planning during each of the	Pending	TP	A				X				
MOD-004-1 Auditable 6/1/2011		R6.1.	Reflect consideration of each of the following if available: a) Any studies (as described in R3.1) performed by Load-Serving Entities for	Pending	TP	A				X				
MOD-004-1 Auditable 6/1/2011		R6.2.	Be allocated as follows: a) For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource	Pending	TP	A				X				
MOD-004-1 Auditable 6/1/2011	R7.		Less than 31 calendar days after the establishment of CBM, the Transmission Service Provider that maintains CBM shall notify all the Load-Serving Entities	Pending	TSP	A				X				
MOD-004-1 Auditable 6/1/2011	R8.		Less than 31 calendar days after the establishment of CBM, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that	Pending	TP	A				X				

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MOD-004-1 Auditable 6/1/2011	R9.		The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide (subject to confidentiality and security requirements)	Pending	TSP, TP	A				X				
MOD-004-1 Auditable 6/1/2011		R9.1.	Each of its associated Transmission Operators within 30 calendar days of their making a request for the data.	Pending	TSP, TP	A				X				
MOD-004-1 Auditable 6/1/2011		R9.2.	To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, Resource Planner, or Planning Coordinator within 30 calendar days of	Pending	TSP, TP	A				X				
MOD-004-1 Auditable 6/1/2011	R10.		The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared	Pending	BA, LSE	A				X				
MOD-004-1 Auditable 6/1/2011	R11.		When reviewing an Arranged Interchange using CBM, all Balancing Authorities and Transmission Service Providers shall waive, within the bounds of reliable	Pending	BA, TSP	A				X				
MOD-004-1 Auditable 6/1/2011	R12.		The Transmission Service Provider that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is	Pending	TSP	A				X				
MOD-004-1 Auditable 6/1/2011		R12.1.	The CBM is available	Pending	TSP	A				X				
MOD-004-1 Auditable 6/1/2011		R12.2.	The EEA 2 is declared within the Balancing Authority Area of the "energy deficient entity," and	Pending	TSP	A				X				
MOD-004-1 Auditable 6/1/2011		R12.3.	The Load of the "energy deficient entity" is located within the Transmission Service Provider's area.	Pending	TSP	A				X				
MOD-006-0.1 Retired 3/31/2011	R1.		Each Transmission Service Provider shall document its procedure on the use of Capacity Benefit Margin (CBM) (scheduling of energy against a CBM	LOWER	TSP									
MOD-006-0.1 Retired 3/31/2011		R1.1.	Require that CBM be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, Direct-Control Load	LOWER	TSP									
MOD-006-0.1 Retired 3/31/2011		R1.2.	Require that CBM shall only be used if the Load-Serving Entity calling for its use is experiencing a generation deficiency and its Transmission Service Provider is also	LOWER	TSP									
MOD-006-0.1 Retired 3/31/2011		R1.3.	Describe the conditions under which CBM may be available as Non-Firm Transmission Service.	LOWER	TSP									
MOD-006-0.1 Retired 3/31/2011	R2.		Each Transmission Service Provider shall make its CBM use procedure available on a web site accessible by the Regional Reliability Organizations, NERC, and	LOWER	TSP									

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MOD-007-0 Retired 3/31/2011	R1.		Each Transmission Service Provider that uses CBM shall report (to the Regional Reliability Organization, NERC and the transmission users) the use of CBM by	LOWER	TSP									
MOD-007-0 Retired 3/31/2011	R2.		The Transmission Service Provider shall post the following three items within 15 calendar days after the use of CBM for an Energy Emergency. This posting shall be	LOWER	TSP									
MOD-007-0 Retired 3/31/2011		R2.1.	Circumstances.	LOWER	TSP									
MOD-007-0 Retired 3/31/2011		R2.2.	Duration.	LOWER	TSP									
MOD-007-0 Retired 3/31/2011		R2.3.	Amount of CBM used.	LOWER	TSP									
MOD-008-1 Auditable 6/1/2011	R1.		Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following	*Pending*	TOP	A				X				
MOD-008-1 Auditable 6/1/2011		R1.1.	Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a	*Pending*	TOP	A				X				
MOD-008-1 Auditable 6/1/2011		R1.2.	The description of the method used to allocate TRM across ATC Paths or Flowgates.	*Pending*	TOP	A				X				
MOD-008-1 Auditable 6/1/2011		R1.3.	The identification of the TRM calculation used for the following time periods:	*Pending*	TOP	A				X				
MOD-008-1 Auditable 6/1/2011		R1.3.1.	Same day and real-time.	*Pending*	TOP	A				X				
MOD-008-1 Auditable 6/1/2011		R1.3.2.	Day-ahead and pre-schedule.	*Pending*	TOP	A				X				
MOD-008-1 Auditable 6/1/2011		R1.3.3.	Beyond day-ahead and pre-schedule, up to thirteen months ahead.	*Pending*	TOP	A				X				
MOD-008-1 Auditable 6/1/2011	R2.		Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of	*Pending*	TOP	A				X				
MOD-008-1 Auditable 6/1/2011	R3.		Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the	*Pending*	TOP	A				X				

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MOD-008-1 Auditable 6/1/2011	R4.		Each Transmission Operator that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months.	*Pending*	TOP	A				X				
MOD-008-1 Auditable 6/1/2011	R5.		The Transmission Operator that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s)	*Pending*	TOP	A				X				
MOD-010-0	R1.		The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of	MEDIUM	GO, RP, TO, TP									
MOD-010-0	R2.		The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of	MEDIUM	GO, RP, TO, TP		A							
MOD-012-0	R1.		The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of	MEDIUM	GO, RP, TO, TP									
MOD-012-0	R2.		The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of	MEDIUM	GO, RP, TO, TP		A							
MOD-016-1.1	R1.		The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a)	LOWER	PA, PC, RRO									
MOD-016-1.1		R1.1.	The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010,	LOWER	PA, PC, RRO									
MOD-016-1.1	R2.		The Regional Reliability Organization shall distribute its documentation required in Requirement 1 and any changes to that documentation, to all	LOWER	RRO									
MOD-016-1.1		R2.1.	The Regional Reliability Organization shall make this distribution within 30 calendar days of approval.	LOWER	RRO									
MOD-016-1.1	R3.		The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its	LOWER	PA, PC									
MOD-016-1.1		R3.1.	The Planning Authority shall make this distribution within 30 calendar days of approval.	LOWER	PA, PC									
MOD-017-0.1	R1.		The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional,	MEDIUM	LSE, PA, PC, RP									
MOD-017-0.1		R1.1.	Integrated hourly demands in megawatts (MW) for the prior year.	MEDIUM	LSE, PA, PC, RP									

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MOD-017-0.1		R1.2.	Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.	MEDIUM	LSE, PA, PC, RP									
MOD-017-0.1		R1.3.	Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.	MEDIUM	LSE, PA, PC, RP									
MOD-017-0.1		R1.4.	Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the	MEDIUM	LSE, PA, PC, RP									
MOD-018-0	R1.		The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast demand data (reported on either	MEDIUM	LSE, PA, PC, RP, TP									
MOD-018-0		R1.1.	Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and	MEDIUM	LSE, PA, PC, RP, TP									
MOD-018-0		R1.2.	Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load.	LOWER	LSE, PA, PC, RP, TP									
MOD-018-0		R1.3.	Items (MOD-018-0_R 1.1) and (MOD-018-0_R 1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-1_R 1.	LOWER	LSE, PA, PC, RP, TP									
MOD-018-0	R2.		The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each report data associated with Reliability Standard MOD-	LOWER	LSE, PA, PC, RP, TP									
MOD-019-0.1	R1.		The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible	MEDIUM	LSE, PA, PC, RP, TP									
MOD-020-0	R1.		The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load	LOWER	LSE, RP, TP									
MOD-021-0.1	R1.		The Load-Serving Entity, Transmission Planner, and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of	LOWER	LSE, RP, TP									
MOD-021-0.1	R2.		The Load-Serving Entity, Transmission Planner, and Resource Planner shall each include information detailing how Demand-Side Management measures are	LOWER	LSE, RP, TP									
MOD-021-0.1	R3.		The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on	LOWER	LSE, RP, TP									
MOD-028-1 Auditable 6/1/2011	R1.		Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following	Pending	TSP	A								

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MOD-028-1 Auditable 6/1/2011		R1.1.	Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission	Pending	TSP	A								
MOD-028-1 Auditable 6/1/2011		R1.2.	A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.	Pending	TSP	A								
MOD-028-1 Auditable 6/1/2011		R1.3.	Any contractual obligations for allocation of TTC.	Pending	TSP	A								
MOD-028-1 Auditable 6/1/2011		R1.4.	A description of the manner in which Contingencies are identified for use in the TTC process.	Pending	TSP	A								
MOD-028-1 Auditable 6/1/2011		R1.5.	The following information on how source and sink for transmission service is accounted for in ATC calculations including:	Pending	TSP	A								
MOD-028-1 Auditable 6/1/2011		R1.5.1.	Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt	Pending	TSP	A								
MOD-028-1 Auditable 6/1/2011		R1.5.2.	Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission	Pending	TSP	A								
MOD-028-1 Auditable 6/1/2011		R1.5.3.	The source/sink or POR/POD identification and mapping to the model	Pending	TSP	A								
MOD-028-1 Auditable 6/1/2011		R1.5.4.	If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how	Pending	TSP	A								
MOD-028-1 Auditable 6/1/2011	R2.		When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following:	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R2.1.	Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R2.2.	Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R2.3.	Facility Ratings specified by the Generator Owners and Transmission Owners.	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011	R3.		When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The	Pending	TOP	A								

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MOD-028-1 Auditable 6/1/2011		R3.1.	For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R3.1.1.	Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R3.1.2.	Load forecast for the applicable period being calculated.	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R3.1.3.	Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R3.2.	For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R3.2.1.	Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R3.2.2.	Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R3.2.3.	Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011	R4.		When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions:	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R4.1.	Use all Contingencies meeting the criteria described in the ATCID.	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R4.2.	Respect any contractual allocations of TTC.	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R4.3.	Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011	R5.		Each Transmission Operator shall establish TTC for each ATC Path as defined below:	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R5.1.	At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.	Pending	TOP	A								

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MOD-028-1 Auditable 6/1/2011		R5.2.	At least once per calendar month for TTCs used in monthly ATC calculations.	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R5.3.	Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011	R6.		Each Transmission Operator shall establish TTC for each ATC Path using the following process:	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R6.1.	Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R6.2.	If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R6.3.	Use (as the TTC) the lesser of: - The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R6.4.	For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011	R7.		The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than:	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R7.1.	One calendar day after its determination for TTCs used in hourly and daily ATC calculations.	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011		R7.2.	Seven calendar days after its determination for TTCs used in monthly ATC calculations.	Pending	TOP	A								
MOD-028-1 Auditable 6/1/2011	R8.		When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETCF) for all time periods for an ATC Path the Transmission Service	Pending	TSP	A								
MOD-028-1 Auditable 6/1/2011	R9.		When calculating ETC for non-firm commitments (ETCNF) for all time periods for an ATC Path the Transmission Service Provider shall use the following	Pending	TSP	A								
MOD-028-1 Auditable 6/1/2011	R10.		When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm:	Pending	TSP	A								
MOD-028-1 Auditable 6/1/2011	R11.		When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm:	Pending	TSP	A								

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MOD-029-1 Auditable 6/1/2011	R1.		When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements:	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.	The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.1.	Includes at least:	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.1.1.	The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.1.2.	All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.1.3.	Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.2.	Models all system Elements as in-service for the assumed initial conditions.	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.3.	Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.4.	Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.5.	Uses Load forecast by Balancing Authority.	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.6.	Uses Transmission Facility additions and retirements.	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.7.	Uses Generation Facility additions and retirements.	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.8.	Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.1.9.	Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.	Pending	TOP	A								

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MOD-029-1 Auditable 6/1/2011		R1.1.10.	Includes any other modeling requirements or criteria specified in the ATCID.	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R1.2.	Uses Facility Ratings as provided by the Transmission Owner and Generator Owner	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011	R2.		The Transmission Operator shall use the following process to determine TTC:	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R2.1.	Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R2.1.1.	When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R2.1.2.	When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R2.1.3.	Uncontrolled separation shall not occur.	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R2.2.	Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line),	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R2.3.	For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R2.4.	For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R2.5.	The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R2.6.	Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R2.7.	For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011		R2.8.	Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the	Pending	TOP	A								

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MOD-029-1 Auditable 6/1/2011	R3.		Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path.	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011	R4.		Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service	Pending	TOP	A								
MOD-029-1 Auditable 6/1/2011	R5.		When calculating ETC for firm Existing Transmission Commitments (ETCF) for a specified period for an ATC Path, the Transmission Service Provider shall use	Pending	TSP	A								
MOD-029-1 Auditable 6/1/2011	R6.		When calculating ETC for non-firm Existing Transmission Commitments (ETCNF) for all time horizons for an ATC Path the Transmission Service Provider	Pending	TSP	A								
MOD-029-1 Auditable 6/1/2011	R7.		When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm:	Pending	TSP	A								
MOD-029-1 Auditable 6/1/2011	R8.		When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm:	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011	R1.		The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID):	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R1.1.	The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R1.2.	The following information on how source and sink for transmission service is accounted for in AFC calculations including:	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R1.2.1.	Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R1.2.2.	Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R1.2.3.	The source/sink or POR/POD identification and mapping to the model.	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R1.2.4.	If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011	R2.		The Transmission Operator shall perform the following: [Violation Risk Factor:	Pending	TOP	A								

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MOD-030-2 Auditable 6/1/2011		R2.1.	Include Flowgates used in the AFC process based, at a minimum, on the following criteria:	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.1.1.	Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.1.1.1.	Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.1.1.2.	Only the most limiting element in a series configuration needs to be included as a Flowgate.	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.1.1.3.	If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.1.2.	Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.1.2.1.	Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.1.2.2.	Only the most limiting element in a series configuration needs to be included as a Flowgate.	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.1.2.3.	If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.1.3.	Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.1.4.	Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.1.4.1.	The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and - Any	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.1.4.2.	The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.2.	At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.	Pending	TOP	A								

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MOD-030-2 Auditable 6/1/2011		R2.3.	At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.4.	Establish the TFC of each of the defined Flowgates as equal to: - For thermal limits, the System Operating Limit (SOL) of the Flowgate.	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.5.	At a minimum, establish the TFC once per calendar year.	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.5.1.	If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R2.6.	Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011	R3.		The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R3.1.	Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R3.2.	Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R3.3.	Updated at least once per month for AFC calculations for months two through 13.	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R3.4.	Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011		R3.5.	Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.	Pending	TOP	A								
MOD-030-2 Auditable 6/1/2011	R4.		When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: - If the	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011	R5.		When calculating AFCs, the Transmission Service Provider shall:	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R5.1.	Use the models provided by the Transmission Operator.	Pending	TSP	A								

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MOD-030-2 Auditable 6/1/2011		R5.2.	Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R5.3.	For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011	R6.		When calculating the impact of ETC for firm commitments (ETCFi) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following:	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R6.1.	The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R6.1.1.	Load forecast for the time period being calculated, including Native Load and Network Service load	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R6.1.2.	Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R6.2.	The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R6.2.1.	Load forecast for the time period being calculated, including Native Load and Network Service load	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R6.2.2.	Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R6.3.	The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts,	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R6.4.	The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R6.5.	The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R6.6.	The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R6.7.	The impact of other firm services determined by the Transmission Service Provider.	Pending	TSP	A								

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MOD-030-2 Auditable 6/1/2011	R7.		When calculating the impact of ETC for non-firm commitments (ETCNFi) for all time periods for a Flowgate the Transmission Service Provider shall sum:	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R7.1.	The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R7.2.	The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R7.3.	The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R7.4.	The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R7.5.	The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R7.6.	The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R7.7.	The impact of other non-firm services determined by the Transmission Service Provider.	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011	R8.		When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011	R9.		When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011	R10.		Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency,	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R10.1.	For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R10.2.	For daily AFC, once per day.	Pending	TSP	A								
MOD-030-2 Auditable 6/1/2011		R10.3.	For monthly AFC, once per week	Pending	TSP	A								

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MOD-030-2 Auditable 6/1/2011	R11.		When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm:	Pending	TSP	A								
			NUCLEAR											
NUC-001-2 Effective 4/1/2010	R1.		The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt	LOWER	Nuclear GO and Nuclear GOP	A			SC		X			
NUC-001-2 Effective 4/1/2010	R2.		The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements[FN1] that include mutually	MEDIUM	Nuclear GOP and Transmission Entities that can include: BA, DP,	A			SC		X			
NUC-001-2 Effective 4/1/2010	R3.		Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning	MEDIUM	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	A					X			
NUC-001-2 Effective 4/1/2010	R4.		Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall:	HIGH	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	A					X			
NUC-001-2 Effective 4/1/2010		R4.1.	Incorporate the NPIRs into their operating analyses of the electric system.	Part of Main Requirement	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	A					X			
NUC-001-2 Effective 4/1/2010		R4.2.	Operate the electric system to meet the NPIRs.	Part of Main Requirement	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	A					X			
NUC-001-2 Effective 4/1/2010		R4.3.	Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.	Part of Main Requirement	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	A					X			
NUC-001-2 Effective 4/1/2010	R5.		The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard.	HIGH	Nuclear GO and Nuclear GOP	A					X			
NUC-001-2 Effective 4/1/2010	R6.		Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall	MEDIUM	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010	R7.		Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission	HIGH	Nuclear GO and Nuclear GOP	A					X			
NUC-001-2 Effective 4/1/2010	R8.		Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator	HIGH	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	A					X			
NUC-001-2 Effective 4/1/2010	R9.		The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s)	MEDIUM	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			

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NUC-001-2 Effective 4/1/2010		R9.1.	Administrative elements:	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.1.1.	Definitions of key terms used in the agreement.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.1.2.	Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.1.3.	A requirement to review the agreement(s) at least every three years.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.1.4.	A dispute resolution mechanism.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.2.	Technical requirements and analysis:	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.2.1.	Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.2.2.	Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.2.3.	Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.3.	Operations and maintenance coordination:	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.3.1.	Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.3.2.	Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.3.3.	Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			
NUC-001-2 Effective 4/1/2010		R9.3.4.	Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					X			

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NUC-001-2 Effective 4/1/2010		R9.3.5.	Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					*X*			
NUC-001-2 Effective 4/1/2010		R9.3.6.	Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					*X*			
NUC-001-2 Effective 4/1/2010		R9.3.7.	Coordination of the NPIRs with transmission system Special Protection Systems and underfrequency and undervoltage load shedding programs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					*X*			
NUC-001-2 Effective 4/1/2010		R9.4.	Communications and training:	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					*X*			
NUC-001-2 Effective 4/1/2010		R9.4.1.	Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					*X*			
NUC-001-2 Effective 4/1/2010		R9.4.2.	Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event,	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					*X*			
NUC-001-2 Effective 4/1/2010		R9.4.3.	Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					*X*			
NUC-001-2 Effective 4/1/2010		R9.4.4.	Provisions for supplying information necessary to report to government agencies, as related to NPIRs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					*X*			
NUC-001-2 Effective 4/1/2010		R9.4.5.	Provisions for personnel training, as related to NPIRs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,	A					*X*			
			PERSONNEL PERFORMANCE, TRAINING AND QUALIFICATIONS											
PER-001-0.1	R1.		Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement	HIGH	BA, TOP	A					*X*	*X*		
PER-002-0	R1.		Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.	HIGH	BA, TOP	A				X	*X*	*X*	*X*	*X*
PER-002-0	R2.		Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:	HIGH	BA, TOP	A				X	*X*	*X*	*X*	*X*
PER-002-0		R2.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk	HIGH	BA, TOP	A				X	*X*	*X*	*X*	*X*

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PER-002-0		R2.2.	Positions directly responsible for complying with NERC standards.	HIGH	BA, TOP	A				X	*X*	*X*	*X*	*X*
PER-002-0	R3.		For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following	HIGH	BA, TOP	A				X	*X*	*X*	*X*	*X*
PER-002-0		R3.1.	A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable	MEDIUM	BA, TOP	A				X	*X*	*X*	*X*	*X*
PER-002-0		R3.2.	The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan	MEDIUM	BA, TOP	A				X	*X*	*X*	*X*	*X*
PER-002-0		R3.3.	The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their	LOWER	BA, TOP	A				X	*X*	*X*	*X*	*X*
PER-002-0		R3.4.	Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.	LOWER	BA, TOP	A				X	*X*	*X*	*X*	*X*
PER-002-0	R4.		For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per	HIGH	BA, TOP	A				X	*X*	*X*	*X*	*X*
PER-003-0	R1.		Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with	HIGH	BA, RC, TOP	A		ER			*X*	*X*	*X*	*X*
PER-003-0		R1.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk	HIGH	BA, RC, TOP	A		ER			*X*	*X*	*X*	*X*
PER-003-0		R1.2.	Positions directly responsible for complying with NERC standards.	HIGH	BA, RC, TOP	A		ER			*X*	*X*	*X*	*X*
PER-004-1	R1.		Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.	HIGH	RC	A				X	*X*	*X*	*X*	*X*
PER-004-1	R2.		All Reliability Coordinator operating personnel shall each complete a minimum of five days per year of training and drills using realistic simulations of	HIGH	RC	A					*X*	*X*	*X*	*X*
PER-004-1	R3.		Reliability Coordinator operating personnel shall have a comprehensive understanding of the Reliability Coordinator Area and interactions with	HIGH	RC	A					*X*	*X*	*X*	*X*
PER-004-1	R4.		Reliability Coordinator operating personnel shall have an extensive understanding of the Balancing Authorities, Transmission Operators, and	HIGH	RC	A					*X*	*X*	*X*	*X*

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PER-004-1	R5.		Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall	HIGH	RC	A					*X*	*X*	*X*	*X*
			PROTECTION AND CONTROL											
PRC-001-1	R1.		Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes	HIGH	BA, GOP, TOP	A				X	*X*	*X*		
PRC-001-1	R2.		Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	HIGH	GOP, TOP	A				X	*X*	*X*		
PRC-001-1		R2.1.	If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority.	HIGH	GOP	A				X	*X*	*X*		
PRC-001-1		R2.2.	If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected	HIGH	TOP	A				X	*X*	*X*		
PRC-001-1	R3.		A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.	No VRF Assigned	GOP, TOP	A				X		*X*		
PRC-001-1		R3.1.	Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host	HIGH	GOP	A				X	*X*	*X*		
PRC-001-1		R3.2.	Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and	HIGH	TOP	A				X	*X*	*X*		
PRC-001-1	R4.		Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators,	HIGH	TOP	A				X	*X*	*X*		
PRC-001-1	R5.		A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require	HIGH	GOP, TOP	A				X	*X*	*X*		
PRC-001-1		R5.1.	Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in	HIGH	GOP	A				X	*X*	*X*		
PRC-001-1		R5.2.	Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating	HIGH	TOP	A				X	*X*	*X*		
PRC-001-1	R6.		Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected	HIGH	BA, TOP	A				X	*X*	*X*		

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PRC-004-1	R1.		The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection	HIGH	DP, TO	A				X	X	X	X	X
PRC-004-1	R2.		The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to	HIGH	GO	A				X	X	X	X	X
PRC-004-1	R3.		The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its	LOWER	DP, GO, TO							X	X	X
PRC-005-1	R1.		Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation	HIGH	DP, GO, TO	A				X	X	X	X	X
PRC-005-1		R1.1.	Maintenance and testing intervals and their basis.	HIGH	DP, GO, TO	A				X	X	X	X	X
PRC-005-1		R1.2.	Summary of maintenance and testing procedures.	HIGH	DP, GO, TO	A				X	X	X	X	X
PRC-005-1	R2.		Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation	LOWER	DP, GO, TO	A				X	X	X	X	X
PRC-005-1		R2.1.	Evidence Protection System devices were maintained and tested within the defined intervals.	HIGH	DP, GO, TO	A				X	X	X	X	X
PRC-005-1		R2.2.	Date each Protection System device was last tested/maintained.	HIGH	DP, GO, TO	A				X	X	X	X	X
PRC-007-0	R1.		The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS	MEDIUM	DP, TO								X	X
PRC-007-0	R2.		The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to	LOWER	DP, LSE, TO, TOP		A						X	X
PRC-007-0	R3.		The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its	LOWER	DP, TO								X	X
PRC-008-0	R1.		The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS	MEDIUM	DP, TO	A				X	X	X	X	X

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PRC-008-0	R2.		The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS	MEDIUM	DP, TO	A				X	*X*	*X*	*X*	*X*
PRC-009-0	R1.		The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by	MEDIUM	DP, LSE, TO, TOP									
PRC-009-0		R1.1.	A description of the event including initiating conditions.	MEDIUM	DP, LSE, TO, TOP									
PRC-009-0		R1.2.	A review of the UFLS set points and tripping times.	MEDIUM	DP, LSE, TO, TOP									
PRC-009-0		R1.3.	A simulation of the event.	MEDIUM	DP, LSE, TO, TOP									
PRC-009-0		R1.4.	A summary of the findings.	MEDIUM	DP, LSE, TO, TOP									
PRC-009-0	R2.		The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by	LOWER	DP, LSE, TO, TOP									
PRC-010-0	R1.		The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall	MEDIUM	DP, LSE, TO, TOP								*X*	*X*
PRC-010-0		R1.1.	This assessment shall include, but is not limited to:	MEDIUM	DP, LSE, TO, TOP								*X*	*X*
PRC-010-0		R1.1.1.	Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.	MEDIUM	DP, LSE, TO, TOP								*X*	*X*
PRC-010-0		R1.1.2.	Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-	MEDIUM	DP, LSE, TO, TOP								*X*	*X*
PRC-010-0		R1.1.3.	A review of the voltage set points and timing.	MEDIUM	DP, LSE, TO, TOP								*X*	*X*
PRC-010-0	R2.		The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide	LOWER	DP, LSE, TO, TOP								*X*	*X*
PRC-011-0	R1.		The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program	MEDIUM	DP, TO	A				X			*X*	*X*

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PRC-011-0		R1.1.	The UVLS system identification which shall include but is not limited to:	MEDIUM	DP, TO	A				X			*X*	*X*
PRC-011-0		R1.1.1.	Relays.	MEDIUM	DP, TO	A				X			*X*	*X*
PRC-011-0		R1.1.2.	Instrument transformers.	MEDIUM	DP, TO	A				X			*X*	*X*
PRC-011-0		R1.1.3.	Communications systems, where appropriate.	MEDIUM	DP, TO	A				X			*X*	*X*
PRC-011-0		R1.1.4.	Batteries.	MEDIUM	DP, TO	A				X			*X*	*X*
PRC-011-0		R1.2.	Documentation of maintenance and testing intervals and their basis.	MEDIUM	DP, TO	A				X			*X*	*X*
PRC-011-0		R1.3.	Summary of testing procedure.	MEDIUM	DP, TO	A				X			*X*	*X*
PRC-011-0		R1.4.	Schedule for system testing.	MEDIUM	DP, TO	A				X			*X*	*X*
PRC-011-0		R1.5.	Schedule for system maintenance.	MEDIUM	DP, TO	A				X			*X*	*X*
PRC-011-0		R1.6.	Date last tested/maintained.	MEDIUM	DP, TO	A				X			*X*	*X*
PRC-011-0	R2.		The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing	LOWER	DP, TO									
PRC-015-0	R1.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed	MEDIUM	DP, GO, TO									
PRC-015-0	R2.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified	MEDIUM	DP, GO, TO									
PRC-015-0	R3.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the	LOWER	DP, GO, TO									

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PRC-016-0.1	R1.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all	MEDIUM	DP, GO, TO								*X*	*X*
PRC-016-0.1	R2.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.	MEDIUM	DP, GO, TO								*X*	*X*
PRC-016-0.1	R3.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation	LOWER	DP, GO, TO			ER					*X*	*X*
PRC-017-0	R1.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in	HIGH	DP, GO, TO	A				X	*X*	*X*	*X*	*X*
PRC-017-0		R1.1.	SPS identification shall include but is not limited to:	HIGH	DP, GO, TO	A				X	*X*	*X*	*X*	*X*
PRC-017-0		R1.1.1.	Relays.	HIGH	DP, GO, TO	A				X	*X*	*X*	*X*	*X*
PRC-017-0		R1.1.2.	Instrument transformers.	HIGH	DP, GO, TO	A				X	*X*	*X*	*X*	*X*
PRC-017-0		R1.1.3.	Communications systems, where appropriate.	HIGH	DP, GO, TO	A				X	*X*	*X*	*X*	*X*
PRC-017-0		R1.1.4.	Batteries.	HIGH	DP, GO, TO	A				X	*X*	*X*	*X*	*X*
PRC-017-0		R1.2.	Documentation of maintenance and testing intervals and their basis.	HIGH	DP, GO, TO	A				X	*X*	*X*	*X*	*X*
PRC-017-0		R1.3.	Summary of testing procedure.	HIGH	DP, GO, TO	A				X	*X*	*X*	*X*	*X*
PRC-017-0		R1.4.	Schedule for system testing.	HIGH	DP, GO, TO	A				X	*X*	*X*	*X*	*X*
PRC-017-0		R1.5.	Schedule for system maintenance.	HIGH	DP, GO, TO	A				X	*X*	*X*	*X*	*X*
PRC-017-0		R1.6.	Date last tested/maintained.	MEDIUM	DP, GO, TO	A				X			*X*	*X*

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PRC-017-0	R2.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its	LOWER	DP, GO, TO	A				X			*X*	*X*
PRC-018-1	R1.		Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002	LOWER	GO, TO									
PRC-018-1		R1.1.	Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)	LOWER	GO, TO									
PRC-018-1		R1.2.	Recorded data from each Disturbance shall be retrievable for ten calendar days..	LOWER	GO, TO									
PRC-018-1	R2.		The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements	LOWER	GO, TO									
PRC-018-1	R3.		The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs	LOWER	GO, TO									
PRC-018-1		R3.1.	Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).	LOWER	GO, TO									
PRC-018-1		R3.2.	Make and model of equipment.	LOWER	GO, TO									
PRC-018-1		R3.3.	Installation location.	LOWER	GO, TO									
PRC-018-1		R3.4.	Operational status.	LOWER	GO, TO									
PRC-018-1		R3.5.	Date last tested.	LOWER	GO, TO									
PRC-018-1		R3.6.	Monitored elements, such as transmission circuit, bus section, etc.	LOWER	GO, TO									
PRC-018-1		R3.7.	Monitored devices, such as circuit breaker, disconnect status, alarms, etc.	LOWER	GO, TO									
PRC-018-1		R3.8.	Monitored electrical quantities, such as voltage, current, etc.	LOWER	GO, TO									

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PRC-018-1	R4.		The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability	LOWER	GO, TO									
PRC-018-1	R5.		The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least	LOWER	GO, TO									
PRC-018-1	R6.		Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing	LOWER	GO, TO									
PRC-018-1		R6.1.	Maintenance and testing intervals and their basis.	LOWER	GO, TO									
PRC-018-1		R6.2.	Summary of maintenance and testing procedures.	LOWER	GO, TO									
PRC-021-1	R1.		Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES	LOWER	DP, TO		A						*X*	*X*
PRC-021-1		R1.1.	Size and location of customer load, or percent of connected load, to be interrupted.	LOWER	DP, TO		A						*X*	*X*
PRC-021-1		R1.2.	Corresponding voltage set points and overall scheme clearing times.	MEDIUM	DP, TO		A						*X*	*X*
PRC-021-1		R1.3.	Time delay from initiation to trip signal.	LOWER	DP, TO		A						*X*	*X*
PRC-021-1		R1.4.	Breaker operating times.	LOWER	DP, TO		A						*X*	*X*
PRC-021-1		R1.5.	Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration	LOWER	DP, TO		A						*X*	*X*
PRC-021-1	R2.		Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability	LOWER	DP, TO									
PRC-022-1	R1.		Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage	MEDIUM	DP, LSE, TOP									
PRC-022-1		R1.1.	A description of the event including initiating conditions.	LOWER	DP, LSE, TOP									

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PRC-022-1		R1.2.	A review of the UVLS set points and tripping times.	MEDIUM	DP, LSE, TOP									
PRC-022-1		R1.3.	A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient	LOWER	DP, LSE, TOP									
PRC-022-1		R1.4.	A summary of the findings.	LOWER	DP, LSE, TOP									
PRC-022-1		R1.5.	For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.	MEDIUM	DP, LSE, TOP									
PRC-022-1	R2.		Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of	LOWER	DP, LSE, TOP									
PRC-023-1 Effective 7/1/2010	R1.		Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit	HIGH	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.1.	Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.2.	Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating of a circuit (expressed in	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.3.	Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.3.1.	An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.3.2.	An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.4.	Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line,	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.5.	Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.6.	Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of	Part of Main Requirement	TO, GO, DP	A				X				

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PRC-023-1 Effective 7/1/2010		R1.7.	Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.8.	Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.9.	Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.10.	Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.11.	For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.12.	When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.12.1.	Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.12.2.	Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.12.3.	Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010		R1.13.	Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such	Part of Main Requirement	TO, GO, DP	A				X				
PRC-023-1 Effective 7/1/2010	R2.		The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8,	MEDIUM	TO, GO, DP	A								
PRC-023-1	R3.		The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals	MEDIUM	PA, PC									
PRC-023-1		R3.1.	The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk	Part of Main Requirement	PA, PC									
PRC-023-1		R3.1.1.	This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.	Part of Main Requirement	PA, PC									

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PRC-023-1		R3.2.	The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.	Part of Main Requirement	PA, PC									
PRC-023-1		R3.3.	The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution	Part of Main Requirement	PA, PC									
			TRANSMISSION OPERATIONS											
TOP-001-1	R1.		Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	HIGH	TOP	A					*X*	*X*		
TOP-001-1	R2.		Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy	HIGH	TOP						*X*	*X*		
TOP-001-1	R3.		Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission	HIGH	BA, GOP, TOP	A					*X*	*X*		
TOP-001-1	R4.		Each Distribution Provider and Load-Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including	HIGH	DP, LSE	A					*X*	*X*		
TOP-001-1	R5.		Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real-time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	HIGH	TOP	A					*X*	*X*		
TOP-001-1	R6.		Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the	HIGH	BA, GOP, TOP						*X*	*X*		
TOP-001-1	R7.		Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden	HIGH	GOP, TOP						*X*	*X*		
TOP-001-1		R7.1.	For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the	HIGH	GOP, TOP						*X*	*X*		
TOP-001-1		R7.2.	For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator	HIGH	TOP						*X*	*X*		

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TOP-001-1		R7.3.	When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer	HIGH	GOP, TOP						*X*	*X*		
TOP-001-1	R8.		During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to	HIGH	BA, RC, TOP	A					*X*	*X*		
TOP-002-2a	R1.		Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	MEDIUM	BA, TOP	A					*X*	*X*	*X*	
TOP-002-2a	R2.		Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study	MEDIUM	BA, TOP						*X*		*X*	
TOP-002-2a	R3.		Each Load-Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal	MEDIUM	BA, GOP, LSE, TSP	A				X	*X*	*X*	*X*	
TOP-002-2a	R4.		Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal	MEDIUM	BA, TOP						*X*	*X*	*X*	
TOP-002-2a	R5.		Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange	MEDIUM	BA, TOP						*X*		*X*	
TOP-002-2a	R6.		Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	MEDIUM	BA, TOP	A				X	*X*		*X*	
TOP-002-2a	R7.		Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single	MEDIUM	BA								*X*	
TOP-002-2a	R8.		Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	MEDIUM	BA								*X*	

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TOP-002-2a	R9.		Each Balancing Authority shall plan to meet Interchange Schedules and Ramps.	LOWER	BA							X	X	
TOP-002-2a	R10.		Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating	MEDIUM	BA, TOP								X	
TOP-002-2a	R11.		The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission	MEDIUM	TOP	A				X	X	X	X	
TOP-002-2a	R12.		The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in	MEDIUM	TSP								X	
TOP-002-2a	R13.		At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that	MEDIUM	GOP						X	X	X	
TOP-002-2a	R14.		Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and	MEDIUM	GOP						X	X	X	
TOP-002-2a		R14.1.	Changes in real output capabilities. (Effective August 1, 2007)	MEDIUM	GOP						X	X	X	
TOP-002-2a		R14.2.	Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	LOWER	GOP						X	X	X	
TOP-002-2a	R15.		Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to	LOWER	GOP						X	X	X	
TOP-002-2a	R16.		Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability	MEDIUM	TOP						X	X	X	
TOP-002-2a		R16.1.	Changes in transmission facility status.	HIGH	TOP						X	X	X	
TOP-002-2a		R16.2.	Changes in transmission facility rating.	HIGH	TOP						X	X	X	
TOP-002-2a	R17.		Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16	HIGH	BA, TOP						X	X	X	
TOP-002-2a	R18.		Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers, and Load-Serving Entities shall	MEDIUM	BA, GOP, LSE, TOP, TSP	A				X	X	X	X	

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TOP-002-2a	R19.		Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system	MEDIUM	BA, TOP						X	X	X	
TOP-003-0	R1.		Generator Operators and Transmission Operators shall provide planned outage information.	No VRF Assigned	GOP, TOP						X		X	X
TOP-003-0		R1.1.	Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next	MEDIUM	GOP, TOP						X		X	X
TOP-003-0		R1.2.	Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission	MEDIUM	RC, TOP						X		X	X
TOP-003-0		R1.3.	Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western	MEDIUM	GOP, TOP						X		X	X
TOP-003-0	R2.		Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment,	MEDIUM	BA, GOP, TOP						X		X	X
TOP-003-0	R3.		Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and	MEDIUM	BA, GOP, TOP						X		X	X
TOP-003-0	R4.		Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	MEDIUM	RC						X		X	X
TOP-004-2	R1.		Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	HIGH	TOP						X	X		
TOP-004-2	R2.		Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe	HIGH	TOP						X	X		
TOP-004-2	R3.		Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages,	HIGH	TOP							X		
TOP-004-2	R4.		If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to	HIGH	TOP						X	X		
TOP-004-2	R5.		Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining	HIGH	TOP						X	X		
TOP-004-2	R6.		Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and	MEDIUM	TOP	A				X			X	X

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TOP-004-2		R6.1.	Monitoring and controlling voltage levels and real and reactive power flows.	MEDIUM	TOP	A				X			*X*	*X*
TOP-004-2		R6.2.	Switching transmission elements.	MEDIUM	TOP	A				X			*X*	*X*
TOP-004-2		R6.3.	Planned outages of transmission elements.	MEDIUM	TOP	A				X			*X*	*X*
TOP-004-2		R6.4.	Responding to IROL and SOL violations.	MEDIUM	TOP	A				X			*X*	*X*
TOP-005-1.1	R1.		Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator	MEDIUM	BA, TOP			ER					*X*	*X*
TOP-005-1.1		R1.1.	Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any additional	MEDIUM	RC			ER					*X*	*X*
TOP-005-1.1	R2.		As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric	LOWER	NERC_Net Users			ER					*X*	*X*
TOP-005-1.1	R3.		Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate	MEDIUM	BA, TOP			ER					*X*	*X*
TOP-005-1.1	R4.		Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them	MEDIUM	PSE			ER					*X*	*X*
TOP-006-1	R1.		Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.	MEDIUM	BA, TOP	A								
TOP-006-1		R1.1.	Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.	MEDIUM	GOP	A								
TOP-006-1		R1.2.	Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission	MEDIUM	BA, TOP	A								
TOP-006-1	R2.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive	HIGH	BA, RC, TOP	A					*X*	*X*		
TOP-006-1	R3.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning	MEDIUM	BA, RC, TOP									

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TOP-006-1	R4.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load	MEDIUM	BA, RC, TOP	A								
TOP-006-1	R5.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating	MEDIUM	BA, RC, TOP	A								
TOP-006-1	R6.		Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable)	HIGH	BA, TOP	A					X	X		
TOP-006-1	R7.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	HIGH	BA, RC, TOP	A					X	X		
TOP-007-0	R1.		A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within	HIGH	TOP			ER			X	X	X	X
TOP-007-0	R2.		Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as	HIGH	TOP			ER			X	X	X	X
TOP-007-0	R3.		A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply	HIGH	TOP						X	X	X	X
TOP-007-0	R4.		The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions	HIGH	RC			ER			X	X	X	X
TOP-008-1	R1.		The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include	HIGH	TOP						X	X		
TOP-008-1	R2.		Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or	HIGH	TOP						X	X		
TOP-008-1	R3.		The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition	HIGH	TOP						X	X		
TOP-008-1	R4.		The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be	MEDIUM	TOP									
			TRANSMISSION PLANNING											
TPL-001-0.1	R1.		The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-	HIGH	PA, PC, TP	A					X	X	X	X

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TPL-001-0.1		R1.1.	Be made annually.	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1		R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1		R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1		R1.3.1.	Cover critical system conditions and study years as deemed appropriate by the entity performing the study.	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1		R1.3.2.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1		R1.3.3.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1		R1.3.4.	Have established normal (pre-contingency) operating procedures in place.	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1		R1.3.5.	Have all projected firm transfers modeled.	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1		R1.3.6.	Be performed for selected demand levels over the range of forecast system demands.	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1		R1.3.7.	Demonstrate that system performance meets Table 1 for Category A (no contingencies).	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1		R1.3.8.	Include existing and planned facilities.	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1		R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1		R1.4.	Address any planned upgrades needed to meet the performance requirements of Category A.	MEDIUM	PA, PC, TP	A					X	X	X	X
TPL-001-0.1	R2.		When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and	MEDIUM	PA, PC, TP								X	X

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TPL-001-0.1		R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-001-0.1		R2.1.1.	Including a schedule for implementation.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-001-0.1		R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-001-0.1		R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-001-0.1		R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation	LOWER	PA, PC, TP								*X*	*X*
TPL-001-0.1	R3.		The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually	LOWER	PA, PC, TP		A						*X*	*X*
TPL-002-0a	R1.		The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is	HIGH	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.1.	Be made annually.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.3.1.	Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.3.11.	Include the effects of existing and planned control devices.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*

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TPL-002-0a		R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.3.5.	Have all projected firm transfers modeled.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system Demands.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.3.7.	Demonstrate that system performance meets Category B contingencies.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.3.8.	Include existing and planned facilities.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.4.	Address any planned upgrades needed to meet the performance requirements of Category B of Table I.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a		R1.5.	Consider all contingencies applicable to Category B.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-002-0a	R2.		When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and	MEDIUM	PA, PC, TP	A				X			*X*	*X*
TPL-002-0a		R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM	PA, PC, TP	A				X			*X*	*X*
TPL-002-0a		R2.1.1.	Including a schedule for implementation.	MEDIUM	PA, PC, TP	A				X			*X*	*X*
TPL-002-0a		R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM	PA, PC, TP	A				X			*X*	*X*

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TPL-002-0a		R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM	PA, PC, TP	A				X			*X*	*X*
TPL-002-0a		R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed	MEDIUM	PA, PC, TP	A				X			*X*	*X*
TPL-002-0a	R3.		The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually	LOWER	PA, PC, TP		A						*X*	*X*
TPL-003-0a Effective 4/23/2010	R1.		The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is	HIGH	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.1.	Be made annually.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.3.1.	Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.3.11.	Include the effects of existing and planned control devices.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*

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TPL-003-0a Effective 4/23/2010		R1.3.5.	Have all projected firm transfers modeled.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system demands.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.3.7.	Demonstrate that System performance meets Table 1 for Category C contingencies.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.3.8.	Include existing and planned facilities.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.4.	Address any planned upgrades needed to meet the performance requirements of Category C.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010		R1.5.	Consider all contingencies applicable to Category C.	MEDIUM	PA, PC, TP	A				X	*X*	*X*	*X*	*X*
TPL-003-0a Effective 4/23/2010	R2.		When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and	MEDIUM	PA, PC, TP								*X*	*X*
TPL-003-0a Effective 4/23/2010		R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM	PA, PC, TP								*X*	*X*
TPL-003-0a Effective 4/23/2010		R2.1.1.	Including a schedule for implementation.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-003-0a Effective 4/23/2010		R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-003-0a Effective 4/23/2010		R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-003-0a Effective 4/23/2010		R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed	MEDIUM	PA, PC, TP								*X*	*X*
TPL-003-0a Effective 4/23/2010	R3.		The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually	LOWER	PA, PC, TP		A						*X*	*X*

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TPL-004-0	R1.		The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.1.	Be made annually.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.2.	Be conducted for near-term (years one through five).	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.3.1.	Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.3.4.	Have all projected firm transfers modeled.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.3.5.	Include existing and planned facilities.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.3.6.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.3.7.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.3.8.	Include the effects of existing and planned control devices.	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.3.9.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand	MEDIUM	PA, PC, TP								*X*	*X*
TPL-004-0		R1.4.	Consider all contingencies applicable to Category D.	MEDIUM	PA, PC, TP								*X*	*X*

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TPL-004-0	R2.		The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities'	LOWER	PA, PC, TP		A						*X*	*X*
			VOLTAGE AND REACTIVE											
VAR-001-1	R1.		Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed,	HIGH	TOP	A				X	*X*	*X*	*X*	*X*
VAR-001-1	R2.		Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency	HIGH	TOP	A				X	*X*	*X*	*X*	*X*
VAR-001-1	R3.		The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.	LOWER	TOP	A				X			*X*	*X*
VAR-001-1		R3.1.	Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.	LOWER	TOP	A				X			*X*	*X*
VAR-001-1		R3.2.	For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.	LOWER	TOP	A				X			*X*	*X*
VAR-001-1	R4.		Each Transmission Operator shall specify a voltage or Reactive Power schedule 1 at the interconnection between the generator facility and the Transmission	MEDIUM	TOP	A				X			*X*	*X*
VAR-001-1	R5.		Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its	HIGH	PSE						*X*	*X*	*X*	*X*
VAR-001-1	R6.		The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system	MEDIUM	TOP	A				X			*X*	*X*
VAR-001-1		R6.1.	When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change	MEDIUM	TOP	A				X			*X*	*X*
VAR-001-1	R7.		The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.	HIGH	TOP						*X*	*X*	*X*	*X*
VAR-001-1	R8.		Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including	HIGH	TOP						*X*	*X*	*X*	*X*
VAR-001-1	R9.		Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.	HIGH	TOP	A				X	*X*	*X*	*X*	*X*

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VAR-001-1		R9.1.	Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when	HIGH	TOP	A				X	*X*	*X*	*X*	*X*
VAR-001-1	R10.		Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30	HIGH	TOP						*X*	*X*	*X*	*X*
VAR-001-1	R11.		After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide	LOWER	TOP								*X*	*X*
VAR-001-1	R12.		The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are	HIGH	TOP						*X*	*X*	*X*	*X*
VAR-002-1.1b	R1.		The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode	MEDIUM	GOP	A				X	*X*		*X*	
VAR-002-1.1b	R2.		Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable	MEDIUM	GOP	A				X	*X*		*X*	
VAR-002-1.1b		R2.1.	When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and	MEDIUM	GOP	A				X	*X*		*X*	
VAR-002-1.1b		R2.2.	When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.	MEDIUM	GOP	A				X	*X*		*X*	
VAR-002-1.1b	R3.		Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:	MEDIUM	GOP	A				X	*X*		*X*	
VAR-002-1.1b		R3.1.	A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system	MEDIUM	GOP	A				X	*X*		*X*	
VAR-002-1.1b		R3.2.	A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status	MEDIUM	GOP	A				X	*X*		*X*	
VAR-002-1.1b	R4.		The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.	LOWER	GO	A					*X*		*X*	
VAR-002-1.1b		R4.1.	For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:	LOWER	GO	A					*X*		*X*	
VAR-002-1.1b		R4.1.1.	Tap settings.	LOWER	GO	A					*X*		*X*	

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VAR-002-1.1b		R4.1.2.	Available fixed tap ranges.	LOWER	GO	A					*X*		*X*	
VAR-002-1.1b		R4.1.3.	Impedance data.	LOWER	GO	A					*X*		*X*	
VAR-002-1.1b		R4.1.4.	The +/- voltage range with step-change in % for load-tap changing transformers.	LOWER	GO	A					*X*		*X*	
VAR-002-1.1b	R5.		After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap	MEDIUM	GO	A					*X*		*X*	
VAR-002-1.1b		R5.1.	If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator	LOWER	GOP	A					*X*		*X*	
					Totals	764	51	41	2	473	*578*	*364*	*534*	*382*

REGISTERED FUNCTION ABBREVIATIONS

BA - Balancing Authority	RC - Reliability Coordinator
DP - Distribution Provider	RE - Regional Entity
GO - Generation Owner	RP - Resource Planner
GOP - Generation Operator	RSG - Reserve Sharing Group
IA - Interchange Authority	TO - Transmission Owner
LSE - Load-Serving Entity	TOP - Transmission Operator
PA/PC - Planning Authority, Planning Coordinator	TP - Transmission Planner
PSE - Purchasing-Selling Entities	TSP - Transmission Service Provider

Revision History

Revision Number	Date	Standard/Process	Description
0	9/18/10	Development	Initial Draft
1	10/1/10	Development	Final Public Version
2	2/15/11	Revision	Removed BA in applicability of BAL-002-0 R2 and subrequirements. Removed BA in applicability of BAL-002-0 R5 and subrequirements. Added CIP-006-3 R8.2; previously omitted. For MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, MOD-030-2 Effective Date 4/1/11 was changed to Auditable Date 6/1/11. Corrected the mislabeling of PRC-023-1 R1.19 to PRC-023-1 R1.13. Corrected TPL-002-0.a to TPL-002-0a. Moved registered entity function designations to footer of Requirements Detail tab. Updated column headers. Updated Summary tab to reflect changes made within the Requirements Detail tab. PERIODIC DATA SUBMITTAL: Changed "S" to "M" for BAL-006-1.1. Changed "S" to "A" for EOP-009-0, MOD-010-0, MOD-012-0 and PRC-007-0. Removed monitoring from BAL-001-0.1a R3 and R4, BAL-006-1.1 R3, MOD-010-0 R1 and MOD-012-0 R1. AUDIT: Changed designator from A to X. Removed "X" from PRC-023-1 R2. Corrected historical information for BAL-002-0. SPOT CHECK: Removed "S" from BAL-003-0.1b R3 and R4, IRO-001-1.1, IRO-002-1, IRO-003-2, IRO-005-2, IRO-006-4.1, IRO-014-1, IRO-015-1, IRO-016-1, MOD-028-1, MOD-029-1, and MOD-030-2. Removed from NUC-001-2 R3-R9 (spot check remains for R1 and R2).
3	4/12/11	Revision	SPOT CHECK: Removed all requirements from BAL-003-1b. AUDIT: Removed "X" from EOP-001-0 R3.4. SELF CERTIFICATION: Removed "A" from EOP-001-0 R3.4.

From: Stacia-Ann Chambers
To: Stacia-Ann Chambers
Subject: NERC: Updated 2012 ERO CMEP Implementation Plan and Actively Monitored List
Date: Wednesday, January 11, 2012 10:26:15 PM
Attachments: image004.png
Importance: High

Announcement

2012 ERO CMEP Implementation Plan and Actively Monitored List

Minor Revision

January 11, 2012

Click here for: 2012 Implementation Plan **Updated Link!!**

Click here for: 2012 Actively Monitored List **Updated Link**

Ladies and Gentlemen:

NERC Compliance Operations has made minor revisions to the 2012 ERO CMEP Implementation Plan and Actively Monitored List. The revisions to the Implementation Plan and Actively Monitored List account for the retirement of EOP-001-0 R2, which was retired on 11/30/2011, and the addition of IRO-009-1, which came into effect on 10/1/2011. Specifically, IRO-009-1 R1 and R2 have replaced EOP-001-0 R2 within the Actively Monitored List as Tier 2 requirements while the remaining requirements of IRO-009-1 have been classified as Tier 3. The remaining requirements of EOP-001-0 remain in effect and have maintained their Tier designations.

Additionally, PER-003-1 and PRC-004-2a were added to the "Standards Detail Tab" of the Actively Monitored List to account for their upcoming enforceability within the 2012 compliance year, being 10/1/2012 and 4/1/2012 respectively. The requirement of these two Reliability Standards are not anticipated to be added to any of the three Tiers for 2012.

The net effect of these revisions has not resulted in any changes for the Tier 1, the minimum audit scope for compliance audits in 2012. Currently the counts for each of the three Tiers are as follows:

2012 AML - Tier 1	Tier 2	Tier 3
274	398	253

For more information or assistance, please contact Kyle Howells or Jim Hughes (via email).

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SNLEnergy
POWER DAILY™
Volume 10 Issue 8 **Thursday, January 12, 2012**

Colo. PUC denies Xcel Energy's request for interim rate increase

by Jeff Stanfield

The Colorado Public Utilities Commission on Jan. 11 denied Xcel Energy Inc.'s request for a $100 million interim rate hike while the utility's full electric rate case is being considered by the PUC.

The PUC said in a news release that the company failed to demonstrate that it would be adversely impacted by maintaining current rates during the six-month period while its request for a $141.9 million rate increase is fully reviewed.

In 2010, the Colorado Legislature passed a law that allows the PUC to consider interim rates if a utility shows it will be hurt if its revenues are deficient during the time period required to hold hearings on the suspended rates. The utility had argued that is now paying for costs that are not covered by existing revenues.

The PUC said Xcel Energy's filing did not adequately justify the need for interim rates and did not demonstrate that the financial integrity of the company would be at risk if the interim rates were not granted. The PUC said the company would be granted recovery of all just and reasonable costs after the hearing process is completed and the utility's rate request is thoroughly reviewed.

Xcel Energy had asked that interim rates be implemented by Jan. 21. A decision on the full request is not expected until this summer.

The company said this was the commission's first important opportunity to exercise its authority under the new state law to approve interim rates, and that those rates

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Sierra Club attacks draft air permit for Entergy coal plant in Arkansas

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With financing secured, construction to begin on SDG&E-backed wind project

MetLife, Northwestern Mutual Life Insurance invest in Alta Wind

CPS Energy, OCI Solar negotiating $1B solar deal

To Market Story

To Market Report

Court rejects EPA's delay on boiler MACT, incinerator rules

by Jonathan Crawford

A federal court declared as unlawful a move by the U.S. Environmental Protection Agency to stay major regulations designed to limit hazardous emissions from boiler and solid waste incinerators.

The U.S. District Court for the District of Columbia ruled Jan. 9 that the EPA needlessly suspended implementation of the boiler MACT rule and the commercial and industrial solid waste incinerators, or CISWI, rule, calling the delay "arbitrary and capricious" and the rules long overdue.

"The court acknowledges that vacating the delay notice likely will have an effect on industry facilities throughout the country," U.S. District Judge Paul Friedman stated in his opinion. "[T]hey will finally, more than 12 years after a clear congressional mandate, have to comply with overdue Clean Air Act

Continued on p 13

National lab finds small but significant reliability downturn over past decade

by Kerry Bleskan

Using data from utilities that account for about half of the country's electric sales, government researchers found "a modest, yet statistically significant" downward trend in reported reliability.

The trend is about a 2% increase per year in the reported average duration and average frequency of power interruptions, leaving out major events, said researchers from the Lawrence Berkeley National Laboratory. They analyzed 10 years of information, 2000-2009, from 155 electric utilities. These utilities together sell about half of the electricity sold in the U.S.

"There has been a modest, yet statistically significant secular trend of decreasing or declining reported reliability over the past 10 years," said the authors of the January 2012 report, "An Examination of Temporal Trends in Electricity Reliability Based on Reports from U.S. Electric Utilities."

Better measuring or worse performance?

The studies the Berkeley Lab team built on "focused only on power interruptions originating in the bulk power system," the study's authors said, but have not accounted for disruptions that began in local distribution

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systems. "Interruptions originating on the bulk power system represent only a small fraction of the power interruptions experienced by electricity consumers," they said. "The vast majority of interruptions experienced by electricity consumers are caused by events affecting primarily the electric distribution system."

After accounting for different reporting practices — "differences in utilities' definition and classification of power interruption events make direct comparisons among data from different utilities problematic and potentially misleading" — the researchers found that reported reliability has been decreasing.

The evidence is mixed as to whether that means actual reliability is getting worse, the scientists said. Newly installed or upgraded automated outage management systems tend to show an uptick in reliability problems, but that is probably because manual methods do not report problems fully. "We also found preliminary but not statistically significant evidence for a so-called 'learning effect' by which reported reliability gradually improves in years subsequent to the initial decrease in reported reliability," the team said.

Anyone studying reliability numbers should take into account whether the data was collected manually or through an automated system, researchers said. "Our findings might suggest that it is simply more accurate measurement of reliability, rather than lower actual reliability, which 'explains' the statistically significant trend of decreasing reported reliability over time. However, our analysis takes this factor into account explicitly and still finds statistically significant secular trends toward lower reported reliability over time," they said.

Although the sample was large, researchers said it is not necessarily representative of the entire U.S. electric power system. "Our data are composed primarily of data from investor-owned utilities and are not drawn evenly from all regions of the U.S.," they said.

They also cautioned that the findings should be considered in the context of other trends and system characteristics. "The average annual trends we find are modest in comparison to the routinely larger year to year variations in the average duration and frequency of power interruptions experienced by utility customers."

Comprehensive info 'lacking'

Major blackouts occur about once a decade, the researchers said, usually prompting widespread re-examination of the relative importance of reliability as compared to cost. "Comprehensive information on the actual reliability of the electric power system and on how proposed changes would affect reliability ought to help inform these judgments," they said, but "comprehensive, national-scale information on the reliability of the U.S. electric power system is lacking."

The study was an attempt to get that ball rolling, the Lawrence Berkeley scientists said. The findings show that much more work is needed to paint a realistic picture of reliability nationwide, the researchers said. "At this point, we cannot say what has caused the observed decreasing trends in reported reliability or why it is taking place," they said, though the lab has ruled out measurement error or bias. "It is extremely appropriate to continue exploring differences among utilities to better understand the sources or causes" of the trends, they said. "It is our hope that the analysis we have conducted to date will help pave the way for these investigations and that they will be used to help ground future decisions about U.S. reliability policy, practices, and technology on a more solid factual base."

The study was funded by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability.

Industry Document: An Examination of Temporal Trends in Electricity Reliability Based on Reports from U.S. Electric Utilities

E-mail this story.

We Energies, Wolverine eye JV to save Presque Isle coal plant from retirement

by Dan Lowrey

Wisconsin Electric Power Co., which does business as We Energies, has signed a letter of intent to evaluate the formation of a joint venture with Wolverine Power Supply Cooperative Inc. to invest in pollution controls at its Presque Isle power plant in Marquette, Mich.

The companies will work to determine the practicality of retrofitting the facility's five active coal-burning units to meet new federal environmental regulations over the next several months.

"Wolverine continues to seek cost-effective base load power supply to serve our member-cooperatives," Eric Baker, president and CEO of Wolverine, said in a Jan. 11 news release. "The prospect of investing in Michigan to upgrade the Presque Isle units appeals to us."

We Energies Executive Vice President Allen Leverett added, "Presque Isle is important to the Upper Peninsula of Michigan and we want to develop a life extension option that is economically beneficial for customers."

Wolverine has been trying to build a new coal-fired plant of its own, but the project is being challenged by environmentalists.

The Presque Isle plant consists of nine coal-fired units, four of which were retired between 2006 and 2009. The active units were put into service in the mid- to late 1970s, according to SNL Energy data. The plant's operating capacity is 431 MW.

Proposed federal environmental regulations have created uncertainty about for the future of the plant, with the potential for retirement in 2017, We Energies said. Company officials have said they believe the EPA failed to allocate sufficient allowances to support minimum levels of generation at Presque Isle. They have also discussed the possibility of switching the plant to burn more low-sulfur Powder River Basin coal to save costs in 2012.

The SNL Energy database shows that the Presque Isle plant took coal in 2011 from two PRB mines: the North Antelope Rochelle job in Wyoming of Peabody Energy Corp. and the Spring Creek mine in Montana of Cloud Peak Energy Inc. It also took coal from Peabody's Foidel Creek mine and Oxbow Mining LLC's Elk Creek mine, both in Colorado.

Wisconsin Electric is a subsidiary of Wisconsin Energy Corp.

COMPANIES REFERENCED IN THIS ARTICLE:

Cloud Peak Energy Inc.	CLD
Oxbow Mining LLC	
Peabody Energy Corp.	BTU
Wisconsin Electric Power Co.	
Wisconsin Energy Corp.	WEC
Wolverine Power Supply Cooperative Inc.	

PR: Wolverine Power Supply Coop: Joint Venture at Presque Isle Power Plant to be Studied

E-mail this story.

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Sierra Club attacks draft air permit for Entergy coal plant in Arkansas

by Matthew Bandyk

Arkansas regulators are facing criticism from the Sierra Club over a draft air permit for the White Bluff coal-fired power plant, which the group argues fails to bring the plant's emissions in line with national standards.

In comments presented to the Arkansas Department of Environmental Quality at a Jan. 10 hearing, the Sierra Club argued that White Bluff operator Entergy Arkansas Inc. has not properly calculated how the 1,659-MW plant can come into compliance with national ambient air quality standards for SO2 and particulate matter.

As a result, the plant's baseline emissions cited in the permit are inaccurate, the group argued, and the permit should be denied. White Bluff is in Jefferson County, Ark.

The Sierra Club said its own modeling of White Bluff's SO2 emission rates, based on five years of meteorological data, suggested that the plant's emissions under the permit will be "well in excess" of standards for how much SO2 can be emitted in hourly periods.

The Entergy Corp. subsidiary, which owns 57% of White Bluff, is attempting to renew its Title V air permit for the plant to allow it to continue to operate. The Jan. 10 hearing was for public comment on the draft permit, after which the Arkansas department will make a final decision.

While the question of White Bluff's air permit is being settled, all parties both for and against the plant are looking to the EPA to determine the fate of a large emissions control project that could be constructed at White Bluff in the coming years. The project, involving the installation of scrubbers and low-NOx burners, is on hold until the EPA weighs in on the Arkansas proposed state air plan that would require the controls.

Sierra Club Arkansas spokesman Lev Guter said Jan. 11 that even if the project proceeds, it would not alleviate the group's concerns about White Bluff's emissions. "To invest and dump so much money into an aging coal plant to extend the life of an enormous polluting source is not a smart way to go about it," he said.

According to an email from Entergy Arkansas spokesman Dan Daugherty, the company does not have a cost estimate for the construction of the scrubber project. But in an Oct. 17, 2011, preliminary decision on the Arkansas air plan, the EPA reported that the installation of a wet scrubber at White Bluff unit 1 would have an annualized cost of about $17.02 million, with a cost-effectiveness of $620 per ton of SO2 removed. Installation of a wet scrubber at unit 2 would have similar costs, according to the preliminary decision.

The EPA decision also suggested that the federal agency may force Arkansas to require more stringent controls at the plant. The EPA did not approve part of the Arkansas plan in regard to White Bluff, finding that its SO2 limit was not "the lowest emission limit achievable."

The agency also made similar conclusions for other types of emissions. The Arkansas Department of Environmental Quality and Entergy "should have considered additional post-combustion controls," such as selective noncatalytic reduction and selective catalytic reduction, that are capable of achieving NOx emission limits well below the NOx presumptive limits, the agency said in its decision.

But the EPA's decision is still preliminary. According to Guter, a final action on the Arkansas plan is expected in February.

Arkansas Electric Cooperative Corp. also owns a substantial stake in White Bluff.

COMPANIES REFERENCED IN THIS ARTICLE:

Arkansas Electric Cooperative Corp.
Entergy Arkansas Inc.
Entergy Corp. **ETR**

Regulatory Filing: Entergy Arkansas Inc.

Industry Document: Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze

E-mail this story.

Ontario grid operator: Wind, natural gas filling gap left by shuttered coal plants

by Susan Nelson

Electricity supply statistics for 2011 from the Ontario Independent Electricity System Operator, or IESO, confirm that wind and natural gas are filling in the gap left by declining coal generation.

The province's coal plants now supply only about 3% of the province's electricity as the plants are shuttered in accordance with

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the government's pledge to shut all coal plants by 2014. The use of hydropower and nuclear power has remained fairly steady over the past four years, the IESO reported in its Jan. 6 summation of supply, demand and prices for 2011.

In addition to noting supply trends, the IESO reported that consumers are managing consumption more actively. "The supply mix is not the only thing that's changing," IESO President and CEO Paul Murphy said. "By reducing their consumption during periods of high demand, and by using new tools and applications to monitor their usage, Ontario's electricity consumers are becoming key partners in maintaining system reliability."

During peak hours of extreme weather conditions in 2011, residential, industrial, commercial and institutional users reduced their consumption more than 500 MW in response to various demand response programs and pricing incentives, the IESO said.

Total electricity consumption in the province dropped only slightly, to 141.5 TWh in 2011 from 142 TWh in 2010. On July 21, 2011, a heat wave pushed the peak hourly demand to 25,450 MW, a 375 MW increase from the peak in 2010.

In 2011, nuclear power supplied more than half of Ontario's power at 85.3 TWh, or 56.9%. The share has increased slightly since 2008, when nuclear power supplied 84.4 TWh, or 53%. Hydropower was equally steady as an energy supply, ranging between 20.4% and 25.5% of supply between 2008 and 2011.

Wind and natural gas supplies increased the most sharply as coal's share plummeted from 14.5% of the supply mix in 2008 to 2.7% in 2011. Although coal now generates a small amount of electricity, the IESO, in its latest 18-month outlook released in November 2011, urged the province to continue some coal-fired generation through 2013 because the plants can be ramped up swiftly when extra supply is needed.

"There are still times when the flexibility of coal units is needed," the IESO said in the outlook for the period December 2011 to May 2013.

Wind increased its share of supply from 0.9% in 2008 to 2.5% in 2011. Wind has been heavily promoted by the Ontario government under its feed-in tariff program, which guarantees developers a 20-year fixed contract for the electricity produced. Natural gas saw its share of supply increase from 6.9% of in 2008 to 14.7% in 2011.

The total cost of power in the province was 7.16 Canadian cents per kWh in 2011, up from 6.52 Canadian cents per kWh in 2010. The cost is the combination of the average weighted wholesale market price and the average global adjustment.

Electricity trading activity between Ontario and its interconnected markets became more sluggish in 2011. Imports fell to 3.91 TWh from 6.4 TWh in 2010, while exports dropped to 12.9 TWh from 15.2 TWh in 2010.

COMPANY REFERENCED IN THIS ARTICLE:

Independent Electricity System Operator

Industry Document: Composition of Ontario's Electricity Supply Mix Continues to Change: Consumer Response Supports Reliability

E-mail this story.

With financing secured, construction to begin on SDG&E-backed wind project

by Andrew Engblom

San Francisco-based NaturEner USA LLC has secured a $320 million construction loan from Morgan Stanley, enabling it to greenlight construction of its 189-MW Rim Rock wind project in Montana.

In a statement, the developer said that with the financing now lined up, it expects to bring the project and its 126 Acciona AW-77 1.5-MW turbines online by the end of the year. The Rim Rock project is in Glacier and Toole counties, Mont., on about 21,000 acres of private land.

The announcement follows a decision by FERC in December 2011 that authorized San Diego Gas & Electric Co. to make a tax equity investment into the project while also purchasing the project's green attributes.

Under the terms of that deal, SDG&E will contribute about $285 million in tax-equity capital, the company said, thus acquiring 100% of the Class B membership interests in NaturEner Rim Rock Project Holding Company LLC. Rim Rock will sell bundled power to SDG&E, and SDG&E will immediately sell the "null" power back to Rim Rock. Morgan Stanley will be the physical offtaker of the power under a long-term fixed power purchase agreement.

"The tax-equity investment, a first for a California regulated utility, is a unique transaction designed to pass through to SDG&E's customers lower utility financing costs," the company said. Rim Rock's output will contribute about 3.5% of SDG&E's renewable portfolio per year.

The power will be shipped via Enbridge Inc.'s Montana Alberta Tie Line within the Western Interconnection. The developer said it has 300 MW of transmission rights that it obtained during a FERC-compliant open season processes conducted in 2005 and 2006.

The announcement that the project is moving forward was quickly praised by Montana Gov. Brian Schweitzer. "This is big news for Montana and the Hi-Line with another $605 million of investment in wind energy development. It will create hundreds of good paying construction jobs and be a sustainable property tax base for local governments," Schweitzer said.

In a separate statement, Mortenson Construction said it would build the project, with completion targeted for October.

The tax-equity investment has also been approved by the California Public Utilities Commission.

NaturEner USA owns and operates the combined 210-MW Glacier Wind projects near Ethridge, Mont. NaturEner Energy Canada Inc., an affiliate of NaturEner USA, is developing wind power projects in Alberta, with more than 500 MW under development, including 375 MW in late-stage development. NaturEner USA LLC and NaturEner Energy Canada Inc. are wholly owned subsidiaries of Spain-based Grupo NaturEner SA, which develops, owns and operates renewable energy facilities.

COMPANIES REFERENCED IN THIS ARTICLE:

Enbridge Inc. **ENB**

NaturEner Energy Canada Inc.

Naturener USA LLC

San Diego Gas & Electric Co.

PR: FERC Authorizes Tax Equity Investment and Green Attributes Power Sale for NaturEner's Rim Rock Project

PR: NaturEner Secures Financing for Rim Rock Project in Montana; Gives Notice to Proceed with Construction

PR: Naturener USA: Governor Brian Schweitzer: 189 MW of New Wind Energy in Montana

E-mail this story.

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MetLife, Northwestern Mutual Life Insurance invest in Alta Wind

by Abby Gruen

MetLife Capital Corp. and the Northwestern Mutual Life Insurance Co. bought interests in Terra-Gen Power LLC's expanding utility-scale Alta Wind Energy Center near Mohave, Calif., from original investor Citibank NA in December 2011.

The planned 3,000-MW capacity Alta Wind Energy Center, in Kern County, has a 1,550-MW power purchase agreement with Edison International utility Southern California Edison Co., and it began delivering electricity in 2011. Five of the announced 11 wind plants are operating, two are under construction and four more are still in the planning stage, according to SNL Energy data.

Permanent financing of Alta Projects I through V was structured as a leveraged lease, under which Citibank committed to buy the projects at the start of commercial operations and lease them back to Terra-Gen, which would continue to manage and operate the projects under long-term agreements.

MetLife bought a 50% membership interest in 150-MW Alta Wind II LLC from Citibank, which retained a 50% interest. MetLife also acquired a 50% interest in 150-MW Alta Wind III, and the Northwestern Mutual Life Insurance Co. acquired the remaining 50% interest from Citibank, according to a Jan. 9 FERC filing (EC10-92).

Google Inc. and Citigroup Inc. each invested $102 million in 168-MW Alta Wind V in June 2011, and they previously invested $55 million each in 102-MW Alta Wind IV. General Electric Co. subsidiary GE Energy Financial Services and UnionBanCal Corp. unit Bankers Commercial Corp. bought the 150-MW Alta Wind I project in January 2011.

UnionBanCal is a subsidiary of Mitsubishi UFJ Financial Group Inc. Terra-Gen Power LLC is an affiliate of ArcLight Capital Partners LLC and Global Infrastructure Partners.

COMPANIES REFERENCED IN THIS ARTICLE:

ArcLight Capital Partners LLC
Edison International **EIX**
GE Energy Financial Services
Southern California Edison Co.
Terra-Gen Power LLC

Company Notice: Terra-Gen Power LLC

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CPS Energy, OCI Solar negotiating $1B solar deal

by Andrew Engblom

San Antonio-based CPS Energy and OCI Solar Power have entered negotiations for a power purchase agreement that could result in the construction of more than $1 billion in solar power projects in Texas.

In a Jan. 11 announcement, the municipal utility and solar project developer said the partnership could result in the development of up to 400 MW of solar capacity as well as the construction of multiple solar manufacturing plants and more than $100 million in capital investment beyond the solar projects. OCI Solar Power also said it would relocate its headquarters to San Antonio along with its engineering and operations center as part of the deal.

"This accelerates San Antonio's leadership in the New Energy Economy, and provides the kind of good-paying, brainpower jobs that are becoming the staple of our local job-creation efforts," San Antonio Mayor Julián Castro said in a statement announcing the potential partnership.

As part of the proposal, the solar projects would become operational in phases over the next five years, CPS Energy said. The output of the projects would be purchased under a 25-year power purchase agreement.

CPS Energy said no date is set yet for the projects to get under way, but the utility said "all parties plan to move expeditiously to negotiate the terms and finalize an agreement." OCI said construction on the first solar facility could begin in 2013 with additional facilities built through 2016, subject to the PPA negotiations.

"In just a few short years, this initiative could help CPS Energy achieve our Vision 2020 goal of attaining 20% or 1,500 MW of renewable resources by the end of the decade," CPS Energy Board Chair Derrick Howard said. "It's a phenomenal opportunity that propels this utility to a leadership position for both wind and solar energy."

CPS Energy said developing the project could result in a projected annual economic impact of $700 million, with construction resulting in a $177 million economic benefit.

Also under the proposal, solar manufacturer Nexolon Co. would serve as the anchor manufacturer for the consortium. Nexolon would build a manufacturing facility and locate its North American headquarters in San Antonio.

COMPANIES REFERENCED IN THIS ARTICLE:

CPS Energy

OCI Solar Power

PR: CPS Energy Attracts Global Manufacturers with Solar Project

PR: OCI Solar Power Enters Negotiations to Develop 400 MW Solar Plant in TX

E-mail this story.

GenOn taps former energy secretary, FERC chair as directors

by Zia Ullah Khan

GenOn Energy Inc. on Jan. 11 said its board appointed former U.S. Energy Secretary Spencer Abraham and former FERC Chairman Betsy Moler to its board of directors.

Abraham, who served as energy secretary from 2001 to 2005, has been chairman and CEO of the international strategic consulting firm the Abraham Group. He serves on the board of Occidental Petroleum Corp.

In addition to serving as FERC member from 1988 to 1997 and as FERC chairman from 1993 to 1997, Moler was deputy secretary of energy from 1997 to 1998, according to a news release. Moler also has served as Exelon Corp.'s executive vice president of governmental affairs and public policy for 10 years.

COMPANIES REFERENCED IN THIS ARTICLE:

Exelon Corp.	**EXC**
GenOn Energy Inc.	**GEN**
Occidental Petroleum Corp.	**OXY**

PR: GenOn Energy Announces Appointment of Two New Directors

E-mail this story.

Manitoba Hydro selects Fortis BC exec as new CEO

by Susan Nelson

Fortis BC Holding Inc. executive Scott Thomson has been named the new president and CEO of Manitoba Hydro following a unanimous recommendation of the utility's board of directors. Thomson is expected to begin work at the utility in mid-February.

"Hydro power is Manitoba's oil and Scott has the experience we need to keep Manitoba Hydro growing for the benefit of all Manitobans," Premier Greg Selinger said in a Jan. 6 statement. "Manitoba Hydro is a well-managed company and with Scott's leadership we will build it into North America's leader in clean, renewable energy."

Thomson comes to the company at a time when leadership will be needed because a rate increase is stalled in an argument with the Manitoba Public Utilities Board over confidentiality of export records that the board would like to see. The company also has been fending off complaints over the route it has chosen for a proposed third transmission line from hydro dams planned in the northern area of the province.

At Fortis BC, a major electric and natural gas utility in British Columbia, Thomson has served as executive vice president of finance, regulatory affairs and energy supply and CFO. Thomson will succeed Manitoba Hydro President and CEO Bob Brennan, who announced plans to retire after nearly 47 years with the company. Brennan will remain with the company until Thomson takes over.

Selinger praised Brennan for his work, saying that under his leadership, "Manitoba Hydro has been highly competitive, powering our province into the new millennia and created stronger relationships with Aboriginal Manitobans."

At Fortis BC, Thomson oversaw long-range financial planning and overall corporate performance measurement and reporting as well as gas procurement and power supply. Thomson also served in senior roles with Ernst & Young.

Manitoba Hydro has taken its refusal to turn over records in the rate case to the courts. The company has refused to divulge the export records without a confidentiality agreement with the Manitoba utilities board. But the board has refused to sign that agreement, saying it is unnecessary. Until that controversy is resolved, a rate increase approved last summer is considered an interim rate.

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The company also is facing criticism from some Manitobans for the routing it has selected for Bipole III, a third transmission line that the company would like to build to bring power from proposed hydro facilities in the north to southern Manitoba for domestic use and export to the United States.

Manitoba Hydro has proposed a route to the west of Lake Winnipeg to avoid a boreal forest on the eastern side that the government would like to keep as a potential UNESCO World Heritage site. A group of 19 engineers, including a former CEO of Manitoba Hydro, have pressed for an eastern routing.

The company wants to begin work on the C$3.28 billion project by the end of 2012, with a projected in-service date of 2017. An environmental impact statement has been submitted to Manitoba Conservation for approval. The 500-kV high-voltage, direct-current line would bring power from the proposed 1,485-MW Conawapa facility and the 695-MW Keeyask facility. Now under construction is the 200-MW Wuskwatim facility.

Manitoba Hydro is a Crown corporation and the major energy utility in Manitoba, with headquarters in Winnipeg. The company serves 537,000 electric customers and 265,000 natural gas customers in the province.

COMPANY REFERENCED IN THIS ARTICLE:

Manitoba Hydro

PR: SELINGER CONGRATULATES NEW MANITOBA HYDRO PRESIDENT

E-mail this story.

Obama visits EPA, defends agency's clean air mission as vital

by Kathleen Hart

In his first-ever visit to the U.S. Environmental Protection Agency, President Barack Obama praised EPA Administrator Lisa Jackson and pledged to stand by the agency's mission of keeping the nation's air and water safe.

"I want to say thank you to each and every one of you, because the EPA touches on the lives of every single American every single day," the president told agency employees Jan. 10. "You help make sure that the air we breathe, the water we drink, the foods we eat are safe. You protect the environment not just for our children but their children. And you keep us moving towards energy independence."

Despite the controversies surrounding many of the EPA's recent rules aimed at cutting emissions of pollutants from power plants and industrial facilities, Obama praised the agency for making the United States stronger. "Our country is stronger because of you. Our future is brighter because of you," he said. "And I want you to know that you've got a president who is grateful for your work and will stand with you every inch of the way as you carry out your mission to make sure that we've got a cleaner world."

The president voiced strong support for Jackson's policies as well as her leadership style. "She has done an extraordinary job leading this agency," he said of Jackson. "But here's what I want all of you to know: Not only is she good on policy, not only is she tough and able to present the EPA's mission so effectively to the public, but she also has your back. She is an advocate on behalf of all the people who work so hard here at the EPA."

Taking on Republicans and industry critics who have argued that the EPA's regulations are killing U.S. jobs in the manufacturing sector, Obama insisted that rules aimed at reducing pollution actually create domestic jobs. "When we put in place new common-sense rules to reduce air pollution, we create new jobs building and installing all sorts of pollution-control technology," he said.

The president's visit to EPA headquarters coincided with the first 2012 presidential primary in New Hampshire on Jan. 10. With the exception of former Massachusetts Gov. Mitt Romney, who won the GOP contest in the Granite State with 39% of the vote, most of the Republican presidential hopefuls have voiced strong opposition to the Obama administration's recent clean air initiatives. Rep. Ron Paul, R-Texas, who placed second in the New Hampshire primary with 23% of the vote, supports eliminating the EPA altogether.

Obama rejected the premise that new regulations limiting emissions of mercury and other pollutants will put the United States at a competitive disadvantage. "Safeguarding our environment is also about strengthening our economy. I do not buy the notion that we have to make a choice between having clean air and clean water and growing this economy in a robust way. I think that is a false debate," he told the agency employees. "We don't have to choose between dirty air and dirty water or a growing economy. We can make sure that we are doing right by our environment and, in fact, putting people back to work all across America. That's part of our mission."

However, Obama also suggested that cost should play a role in environmental regulations. The administration must make sure that its environmental goals are achieved "in the most efficient ways possible, in the least bureaucratic ways possible, in the clearest ways possible. That's also part of our mission," he said.

Industry Document: Remarks by the President to EPA Staff

E-mail this story.

EPA debuts greenhouse gas reporting program, reveals 2010 emissions data

by Jonathan Crawford

The U.S. Environmental Protection Agency on Jan. 11 released for the first time greenhouse gas data collected under its Greenhouse Gas Reporting Program, giving the public an unprecedented peek at emission levels of facilities across the nation.

The EPA program, which features 2010 data from more than 6,700 facilities representing about 80% of the total U.S. greenhouse gas emission output, will usher in a whole new level of transparency that the EPA hopes will spur reductions of such pollutants.

"The Greenhouse Gas Reporting Program data provides a critical tool for businesses and other innovators to find cost- and fuel-saving efficiencies that reduce greenhouse gas emissions, and foster technologies to protect public health and the environment," Gina McCarthy, assistant administrator of EPA's Office of Air and Radiation, said during a Jan. 11 media conference call.

McCarthy said the data can be used by communities to identify local sources of greenhouse gas emissions, businesses to identify cost-saving opportunities, state and local officials to inform policy-making, and the financial and investment communities to inform their decision-making. The tool provides granular data on types and levels of emissions at the facility-level.

With the launch of the program, the EPA released emissions data for 2010 that showed that power plants were the largest stationary source of direct emissions that year, with 2,324 million metric tons of carbon dioxide equivalent. Of the 100 facilities that reported emis-

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sions over 7 million metric tons of carbon dioxide equivalent, 96 were power plants.

The program tracks facilities that directly emit 25,000 metric tons of carbon dioxide equivalent or more per year as well as suppliers of products that release the greenhouse gases when used. It does not include emissions from agriculture or land use. Carbon dioxide and other pollutants are cited by the EPA as a major contributing factor to global warming that causes the Earth's climate to change.

An additional 12 source categories will begin reporting their 2011 greenhouse gas data in 2012, which is expected to bring the coverage of national greenhouse gas emissions to up to 90% of the total emitted.

McCarthy also indicated that the agency is poised to propose by the end of January its controversial greenhouse gas new source performance standards for new, modified and reconstructed power plants. Currently, it is undergoing interagency review.

Many industry groups have been critical of the greenhouse gas reporting requirement, which was mandated by Congress, due to concerns about the costs involved and the disclosure of information that could be exploited for competitive intelligence.

McCarthy said she is optimistic about the Greenhouse Gas Reporting Program. "We have a strong hope that this information will be a strong driver for greenhouse gas reductions," she said, noting that better information makes for a better-informed public and better decision-making.

Industry Document: Greenhouse Gas Reporting Program: 2010 Data Publication

Industry Document: Key Figures Summarizing 2010 Greenhouse Gas Data

Industry Document: 2010 Greenhouse Gas Emissions Data from Large Facilities Now Available / First Release of Data through the National GHG Reporting Program

E-mail this story.

Calif. governor angers industry with proposal to tap carbon cap-and-trade revenue

by Jeff Stanfield

California Gov. Jerry Brown's proposed 2012-2013 state budget, released Jan. 5, calls for spending $1 billion on a wide range of greenhouse gas reduction programs from money expected to be collected from emission allowances through a carbon emissions cap-and-trade program the state plans to begin this year.

However, manufacturing and business representatives contend that unless proceeds are spent directly on helping emissions reduction efforts of companies who must buy the allowances, the auction will constitute an illegal tax.

By assessing a cost to emit carbon dioxide and other greenhouse gases, the state hopes to raise substantial funds to support efforts to address greenhouse gas emissions, Brown said. "Fee proceeds from the cap and trade auctions are expected to be $1 billion in the first year of the program," the governor's proposed budget said. "In the coming years, the auctions will generate substantially more in fees as the program phases in other major GHG emitters."

Neither Brown nor his budget proposals specified how the money would be allocated. But the budget proposal said auction proceeds will support technologically feasible and cost-effective reductions in greenhouse gases. It will support efforts to invest in local communities where air is particularly polluted.

Funding will be directed to cut emissions through energy efficiency, renewable distributed energy generation, and actions at public universities, state and local public buildings, and industrial facilities. Money from the auctions will also cut emissions through development of advanced vehicles and infrastructure, biofuels and low-carbon public transportation, the proposed budget said.

The money will also be directed to reduce emissions associated with water supply, land, natural resource conservation and agriculture, transportation and housing, the proposal said.

The fees will be deposited in the Greenhouse Gas Reduction Account within the Air Pollution Control Fund.

Because actual revenues cannot be certified until late in the fiscal year, specific expenditures are not included in the budget. Instead the budget provides that an expenditure plan be jointly submitted by the director of finance and the California Air Resources Board. That plan will outline specific expenditures and must be submitted at least 30 days prior to allocating funds, the proposed budget said. CARB adopted the cap-and-trade program in October 2011 and is responsible for regulating greenhouse gases.

The budget proposal outraged manufacturers in California, who said the governor proposes to spend auction money on environmental programs that are outside the scope of the cap-and-trade program.

"Before the cap-and-trade system is even started, the state is chomping at the bit to spend precious resources extracted from struggling California companies in the first year of the program for purposes unrelated to companies' efforts to reduce emissions at their facilities," California Manufacturers and Technology Association Vice President of Communications Gino DiCaro said in a Jan. 6 blog post.

Misuse of the funds raised in the program will hurt the state's greenhouse gas reduction law and the cap-and-trade program, DiCaro continued. "It will drive critical new investment, jobs and innovation away from our great state."

Dorothy Rothrock, representing the AB 32 Implementation Group, a coalition of employers and taxpayer groups advocating for policies to limit the impact of greenhouse gas emission reductions on jobs and the economy, expressed similar concerns.

"We are greatly concerned that the governor's budget would allow use of $1 billion raised in the AB 32 cap and trade program in a manner that is beyond the scope of authority under AB 32 and the California constitution," Rothrock said in a press release. "The purpose of cap and trade is to reduce greenhouse gas emissions from regulated sources — including manufacturers, electric generators, universities, and public agencies. AB 32 and cap and trade is not intended to be a revenue source for the state of California."

Yet, the governor is proposing to treat the anticipated $1 billion as windfall revenue and would constitute a new tax on California's businesses, Rothrock said.

"The funds will be paid by California employers suffering the worst recession since the Great Depression," she said. "To avoid litigation and protect jobs, the revenues should be maintained within the cap-and-trade program and must be used in a manner that meets the requirements of a legal fee."

The California Constitution requires that fees provide either a direct benefit or service to the fee payer, or be directly connected to a reasonable regulatory program serving the fee payers. Otherwise,

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these fees are actually taxes and must be approved by a two-thirds vote of the Legislature.

Brown said in his budget message that when he assumed office, the state faced a $26.6 billion budget gap. But through severe cuts and reduced borrowing costs, the 2011 budget reduced the shortfall to $5 billion or less. Still, he said, "The stark truth is that without some new taxes, damaging cuts to schools, universities, public safety and our courts will only increase."

Yet, industry and manufacturers say heavy taxes are causing businesses to flee the state. Businesses in competing states have much lower tax burdens, they claim. The California Chamber of Commerce has called the cap-and-trade program a "haircut" for regulated industries because it arbitrarily sets a requirement that they buy 10% of their allowances at the start of the program.

The chamber called it an unjustified tax on business that will lead to leakage of production and jobs to other states because California is the only state in the nation that requires carbon reductions. The chamber said it has long maintained that CARB's proposal to raise funds via an auction for reasons outside of administrative fee purposes is beyond the board's regulatory authority.

Industry Document: Cap-and-Trade Revenue is not a Budget Solution

Industry Document: Letter from Brenda M. Coleman to Mary Nichols

Industry Document: Proposed Budget Summary

E-mail this story.

Macquarie dims Northeast Utilities view, sees better value without NSTAR

by Amy Poszywak

In the aftermath of a series of bumps in the road for Northeast Utilities and NSTAR's proposed merger, Macquarie (USA) Equities Research on Jan. 9 downgraded Northeast Utilities, going as far as to say the company would be better off alone.

"We now believe that NU's valuation would look best without the [NSTAR] deal, though we don't expect management to walk away," analyst Andrew Weisel wrote in a research report released following the Jan. 6 regulatory hearing in Massachusetts on the proposed merger. He downgraded Northeast Utilities to "underperform" from "neutral."

The hearing had been scheduled for parties to present arguments related to the Massachusetts Department of Energy Resources' motion to stay the merger proceedings at the state Department of Public Utilities.

Weisel said in the report that after attending the hearing, Macquarie believes the utilities will end up sharing at least half of the project merger synergies with the state. In Connecticut, where the Public Utilities Regulatory Authority is in the process of asserting jurisdiction to review and approve or deny the planned combination, Macquarie expects an even less favorable result.

The analyst said the result of these regulatory hurdles is likely to be dilutive to Northeast Utilities.

"Assuming NU needs to share at least 50% of synergies, we forecast dilution of 2-3%, even after accounting for an equity issuance in 2014 that we estimate NU would otherwise need without the deal," Weisel wrote. "We value the pro-forma company at US$34.30-36.25, depending on how synergies are shared with ratepayers vs. US$36 as a standalone. Even with the lower dividend yield, we believe NU is best off without the deal."

Macquarie also lowered its 2014 and 2015 stand-alone EPS for Northeast Utilities to $2.59 and $2.65, respectively, from $2.69 and $2.76, and reduced its target price to $34.50 from $36. Without the merger, Weisel said, Macquarie would value the stand-alone Northeast Utilities at $36.

CreditSights analyst Scott Greenstein took a slightly different view on the topic, saying Jan. 9 that despite the setbacks, CreditSights still likes the transaction because the merger will have benefits for both parties, including results of the consolidation of transmission in the Northeast, he said.

"Certainly politically, they have misstepped in some aspects, but we still believe that the deal itself is just as beneficial as [Progress Energy Inc.] will be for [Duke Energy Corp.]," Greenstein said. "We believe that NU approached NSTAR because they wanted to benefit from a ratings perspective … buying an A-rated utility if you're mid-BBB, possibly threatened to be low BBB, we know the agencies like that."

Additionally, following the Jan. 4 news that the Connecticut Public Utilities Regulatory Authority may end up reviewing the merger, Wells Fargo Securities LLC reiterated its "outperform" rating on Northeast Utilities and NSTAR, "despite heightened merger risk."

Wells Fargo analyst Neil Kalton said that while the event could result in risk around the timeline and outcome of the merger, Wells Fargo continues to believe the transaction will close.

COMPANIES REFERENCED IN THIS ARTICLE:

Duke Energy Corp.	DUK
Northeast Utilities	NU
NSTAR	NST
Progress Energy Inc.	PGN

E-mail this story.

Mass. agency withdraws request for NSTAR rate review tied to merger ruling

by Amy Poszywak

The Massachusetts Department of Energy Resources has withdrawn a request with the state Department of Public Utilities that it stay proceedings in its review of the proposed acquisition of local utility NSTAR by Northeast Utilities until a formal review of NSTAR's rates is done, NSTAR spokeswoman Caroline Allen confirmed Jan. 11.

The request for a rate review was part of a motion the DOER filed with the DPU in June 2011 asking for a stay of proceedings until Northeast Utilities and NSTAR provide a more detailed merger integration plan, a climate change impact analysis and a proposed schedule of expected changes to rates post-merger. NSTAR claimed that if the rate review had become a part of the approval process, it could have derailed the deal by pushing the process past the merger deadline, which is now April 16.

The DOER held on to the part of the motion asking for more integration and impact details before the DPU proceeds in the matter, Allen confirmed. The energy agency also said it supports the state attorney general's previous suggestion that the DPU condition its approval of the deal on the utilities agreeing to either a five-year rate

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freeze with an annual earnings review or for a merger savings credit for Massachusetts customers to be included in the next rate case.

Either condition would apply to the combined company and its three Massachusetts utilities.

Regulators, according to *The Boston Globe*, favored the idea of Northeast Utilities and NSTAR offering up a portion of their expected merger savings in the state in the form of a rate credit to customers. Those savings, according to an analysis conducted by the companies in the first half of 2011, are expected to be about $315 million over 10 years in Massachusetts, and an attorney for NSTAR said during a hearing Jan. 6 that the company "would certainly consider and agree to a situation where there was an up-front credit equal to, say, 50 percent of what the anticipated savings will be."

The companies had originally planned to pass savings along to customers through traditional rate cases, but told regulators at the hearing Jan. 6 that they would consider an up-front rate credit, Allen said. Northeast Utilities and NSTAR are expected to file a reply at the DPU as early as next week.

"We are pleased that the DOER has dropped its request for a rate hearing, we see it as a positive step for the merger, because typically a rate proceeding would take several months, and would have no bearing on the merger" Allen said. "During [the Jan. 6] hearing, we agreed to take the concept of a rate credit for customers under consideration and we pledge to respond to the DPU in a timely fashion."

COMPANIES REFERENCED IN THIS ARTICLE:

Northeast Utilities	NU
NSTAR	NST

Proxy: NSTAR (NST)

E-mail this story.

Bonneville, NorthWestern Energy may collaborate on 500-kV MSTI line

by Kerry Bleskan

The Bonneville Power Administration is considering a role in NorthWestern Energy's 500-kV Mountain States Transmission Intertie project between Montana and Idaho.

The federal power marketing agency and the NorthWestern Corp. subsidiary said Jan. 11 that they have agreed to complete economic and engineering viability studies by July 31, along with a methodology for allocating the line's capacity and cost. The methodology will contemplate other partners in the project, as well as what will be done with unsubscribed capacity and related costs.

Bonneville will use the study results to inform decisions on future participation but did not appear to be committing itself to a future partnership if study results are favorable. "We are eager to see what BPA might gain from being part of this project," said Brian Silverstein, Bonneville's senior vice president of transmission services. "Participation in the MSTI project could help us with our requirement to serve our customers in and around southeastern Idaho and provide other benefits."

Bonneville serves its customers in and around southeastern Idaho, including some parts of western Wyoming and southern Montana, with the help of PacifiCorp through two transfer agreements, the South Idaho Exchange Agreement and the PacifiCorp General Transfer Agreement. The south Idaho agreement expires in 2016.

Bonneville is not looking to renew the agreement, spokesman Doug Johnson said in a Jan. 11 email, but is investigating and evaluating a number of other possibilities. "We have many short-term and long-term options to examine, including building a new transmission line, joining other utilities in a transmission line project, acquiring additional power from the Rocky Mountain/inland southwest market area or a combination of these options," he said.

The MSTI project would run 430 miles from a new substation five miles south of Townsend, Mont., to an Idaho Power Co. substation called Midpoint near Jerome, Idaho. After being held up for a year by a court challenge from Montana's Jefferson County, a favorable ruling in October 2011 from the Montana Supreme Court got state and federal environmental reviews moving along once again, and a draft environmental impact statement is expected midyear. NorthWestern plans to energize the project in 2016.

Bonneville will decide later in 2012 whether to participate in another 500-kV project in the region, the 300-mile Oregon-to-Idaho Boardman-Hemingway line, along with Idaho Power and PacifiCorp.

PacifiCorp is a subsidiary of MidAmerican Energy Holdings Co. Idaho Power is an IDACORP Inc. subsidiary.

COMPANIES REFERENCED IN THIS ARTICLE:

Bonneville Power Administration	
IDACORP Inc.	IDA
Idaho Power Co.	
MidAmerican Energy Holdings Co.	
NorthWestern Corp.	NWE
PacifiCorp	

PR: NorthWestern and BPA Agree to Discuss Ways to Collaborate on MSTI Project

E-mail this story.

Developers of Champlain Hudson line again seek extension to reach settlement

by JP Finlay

Developers of the Champlain Hudson Power Express transmission line asked New York regulators to extend the time period for settlement negotiations on their proposed project until Feb. 17. The request follows a New York Public Service Commission decision in November 2011 to extend the deadline for negotiations to Jan. 10.

As a result of "extensive settlement negotiations," the parties have developed a schedule that could result in the filing of a joint proposal in the proceeding on or before Feb. 17, 2012, "provided no unforeseen obstacles are encountered between now and then," the developers said in a Jan. 10 report to the PSC on the status of settlement negotiations.

CHPE is a proposed 355-mile, 1,000-MW high-voltage, direct-current transmission line between the New York-Canada border, where it would connect with the Hydro-Québec transmission system, and Yonkers, N.Y. The project developer is Toronto-headquartered Transmission Developers Inc.

Donald Jessome, president and CEO of Transmission Developers, said the settlement negotiations have been ongoing for more than a year. "We're not quite there, but we're getting close," Jessome said in a Jan. 11 interview of the settlement negotiations.

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The negotiations include 30 stakeholders such as the New York Power Authority, the Adirondack Park Agency and the Independent Power Producers of New York Inc. Also, utility companies Consolidated Edison Co. of New York Inc. and National Grid USA participated in the talks, along with county and city officials.

One stakeholder in the negotiations, the International Brotherhood of Electrical Workers Local 97, wrote to PSC Chairman Garry Brown to object to the proposed line. A union official said the CHPE line does not address congestion issues in the state that prevent upstate power from moving downstate to consumers.

New York state Sen. George Maziarz, who chairs the state Senate Energy and Telecommunication Committee, also argued that CHPE does not address congestion issues in the state since it imports power from Québec. He said the line does not allow for power producers in upstate New York to connect and bring power to the New York City area.

In a recent speech, New York Gov. Andrew Cuomo advocated for an "energy highway" to be built in New York that will bring electricity south, much like the CHPE line intends to do, but Cuomo did not mention the line by name.

"We're working with all of the parties diligently to resolve all issues. It's difficult to resolve all of the parties' different issues," Jessome said. "At the end of the day, some issues might not get resolved and that's part of the development process."

Because the transmission line would have an international crossing, federal permits would be required in addition to New York state permits. Jessome said plans call for a ramp-up on the federal permitting once the joint proposal has been filed. "Our focus has been very much at the state level for the past year," he said.

Con Edison is a unit of Consolidated Edison Inc. National Grid USA is a subsidiary of National Grid plc.

COMPANIES REFERENCED IN THIS ARTICLE:

Consolidated Edison Co. of New York Inc.
Consolidated Edison Inc. **ED**
Hydro-Québec
National Grid plc
National Grid USA
New York Power Authority
Transmission Developers Inc.

Misc: TDI

E-mail this story.

Maine governor against proposed renewable energy ballot measure

by Kelly Harrington-Andrejasich

Maine Gov. Paul LePage is warning voters against supporting a proposal to bring more renewable resources online by 2020.

In a radio address Jan. 7 and remarks to a wood industry group on Jan. 9, LePage spoke out against an effort to require 20% of Maine's electricity to come from new renewable energy sources by 2020. The Maine Clean Energy Coalition is behind the proposal, which would also require electric utilities to invest in cost-effective energy efficiency, and is collecting signatures for the initiative to appear on the state's November ballot.

Existing RPS regulations adopted in 1999 required providers to get 30% of their supply from renewable sources. Legislation passed in 2007 added a second requirement that by the end of 2017, suppliers get 10% of their electricity from new renewable sources, defined as those entering service after Sept. 1, 2005. Suppliers were supposed to get 1% of their resources from new, or "Class I," sources in 2008, increasing by increments of 1 percentage point each year through 2017.

LePage, in his radio address, said the effort will be harmful to Maine residents, increasing costs to ratepayers at the benefit of "a select few special interest groups in Augusta." Instead of the government mandating use of certain generation sources, the governor said ratepayers should make that choice.

"I support all forms of renewable energy sources that are cost-effective and sustainable," he said. "I do not support ratepayers being forced to buy certain types of alternative energy, against their own will — especially if it's more expensive."

LePage said the proposal would add hundreds of millions of dollars to consumers' electricity bills to benefit a few developers and generators who "have come to realize that their technologies cannot compete in the free market and therefore must receive subsidies to survive."

In a fact sheet on the group's website, the coalition said the ballot initiative would result in a drop in the use of fossil fuels and make Maine more energy independent. The coalition called the clean energy sector "a bright spot" in the economy.

"Increasing energy efficiency and transitioning to local renewable generation will help lower energy costs, stabilize energy prices, and improve the bottom line for Maine's businesses and household," the group said.

The governor followed up his remarks a few days later during an appearance before the Maine Wood Products Association. According to a report from the *Bangor Daily News*, the governor again urged that Maine residents consider the issue before signing a petition in favor of the proposal. He also favors expedited permitting for natural gas and hydroelectric resources.

The Natural Resources Council of Maine is part of the coalition pushing the ballot drive. The council's clean energy director, Dylan Voorhees, said the energy efficiency part of the initiative is just as important as the renewable energy portion.

"The purpose of this initiative is to reduce Maine's overdependence on imported fossil fuels and address our energy problems, and we think it's the recipe for what Maine needs," he said.

The best way to address the cost of energy is to invest in energy efficiency, which will lower costs to ratepayers, and use more in-state renewable sources, which will be more economical over the long term, the coalition said. The coalition needs roughly 58,000 valid signatures to get the measure on the ballot. Those signatures should be filed by the end of the month, Voorhees said.

Industry Document: Weekly Message

Industry Document: Increasing Maine's Energy Independence, Controlling Energy Costs, Creating Jobs and Cleaner Air

E-mail this story.

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Ga. governor calls for repeal of sales tax on energy for manufacturing

by Kelly Harrington-Andrejasich

Georgia Gov. Nathan Deal is calling for the repeal of a sales tax on energy used in manufacturing, saying the change will attract business to the state.

In a Jan.10 speech at an event hosted by the Georgia Chamber of Commerce, Deal said the sales tax is intended to be a tax on consumption and therefore should not be applied to business inputs. "In an age of much higher energy costs, this will impact a large component of manufacturers' overall cost structure and vastly improve the competitive position of our producers," he said.

Deal said Georgia businesses are now making decisions to expand manufacturing and facilities in neighboring states. "Every time they make that decision, we miss out on new investment in our communities and new job opportunities for Georgians," he said.

Money collected from the sales tax goes to the state and its loss would not impact Georgia Power Co., company spokesman Mark Williams said. In fact, the Southern Power Co. subsidiary believes industry would benefit from an elimination of the tax, he said.

Repeal of the sales tax is part of a larger agenda aimed at making Georgia the top state in the country in which to do business. The proposal stems from an effort the governor launched in 2011 called the Georgia Competitiveness Initiative, which included a mix of public officials and business representatives seeking ways to bring business growth to the state.

The Georgia Public Service Commission in 2011 asked state lawmakers to consider in the 2012 legislative session removing a sales tax on energy sales used in manufacturing, saying the move would help keep manufacturing jobs in the state.

COMPANIES REFERENCED IN THIS ARTICLE:

Georgia Power Co.

Southern Power Co.

Industry Document: Eggs and Issues: Creating a More Competitive Georgia through Enhanced Infrastructure, a More Attractive Tax Climate and Improved Schools

E-mail this story.

Hoku asks state regulators to save it from Idaho Power energy contract

by Jeff Stanfield

Hoku Materials Inc. on Jan. 9 asked Idaho state regulators to stop Idaho Power Co. from charging about $2 million per month for power the solar panel substance maker says it is not using and to block the utility from terminating electric service to Hoku's new plant that is about to start commercial operation.

The Hoku Corp. subsidiary said it consumed only $2,732 worth of power during one particular month and yet Idaho Power is seeking a gross profit of nearly $1.89 million on the November 2011 bill alone.

"We feel that it is fair to seek an amendment to the contract based on the dramatic difference between the amounts we are paying for power, the amount of power we are actually consuming, and our understanding of the minimal cost that the utility is incurring to provide service to Hoku," Hoku Corp. CEO Scott Paul said in a news release.

The Idaho Public Utilities Commission will hear oral arguments Jan 11 on Hoku's complaint opposing Idaho Power's intent to terminate electric service to the new polysilicon manufacturing plant in Pocatello.

Hoku was to have paid IDACORP Inc. subsidiary Idaho Power its $1.9 million electric bill by Dec. 21, 2011, or have service terminated Jan. 3.

But Hoku filed a complaint asking that payment for its delinquent November 2011 invoice be taken from a $4 million deposit Hoku has provided the utility. Hoku also asked the PUC to stop Idaho Power from further billing the company for power it does not use, starting with December 2011. Service cannot be terminated while the complaint is pending.

Hoku acknowledged that it has not paid its November bill because the plant is not yet "operational and producing revenue" and must draw on various reserves or loans to pay its operating costs. Also, Hoku asked the PUC to preclude Idaho Power from attempting to terminate service for nonpayment of a claimed $1.8 million deposit balance in addition to what Hoku has already paid. Hoku said Idaho Power unilaterally demanded a deposit of $5.8 million, but that amount is not part of an energy service agreement the two companies entered.

Hoku claimed that termination of service would prevent completion of the plant's construction, possibly damage or destroy sensitive electronic equipment and chemicals that must be protected from freezing, and could cause the loss of many jobs.

Under the service agreement Hoku has with Idaho Power, which started in April 2011, Hoku became obligated to pay energy charges for a first block of power each month regardless of whether it actually consumed energy.

Hoku said that while the agreement created a contractual obligation to pay, the agreement also contains a provision that allows Hoku to request a waiver of monthly first-block payments. "Idaho Power's refusal to grant relief under the safety valve clause is at the core of this dispute," Hoku said in its response filing. However, Hoku acknowledged that this grants Idaho Power sole discretion as to whether to grant relief.

In its earlier complaint, Hoku asked the commission to supervise the waiver decision. Hoku said that until November 2011, it was not even interconnected to Idaho Power's delivery system. Yet, between April and November 2011, Hoku said in its Jan. 9 response, it paid Idaho Power a total of $11.57 million in minimum charges "despite the fact that Idaho Power did not deliver a single electron of electricity to the Hoku facility."

Also, Hoku pointed to a previous decision in which the PUC granted Hoku's waiver of a first-block energy payment after the plant opening was delayed. The PUC had concluded that the unwinding of long positions in which Idaho Power had arranged for future energy deliveries to Hoku could be a net cost or benefit to other customers but was estimated to be small or nonexistent.

In September 2008, Hoku agreed to pay Idaho Power the entire $18 million cost of constructing a six-mile, 138-kV transmission line and a substation, plus other facilities for the supply up to 82 MW to the Hoku plant. Idaho Power assumed ownership of those facilities.

"Thus, neither Idaho Power nor its other customers are burdened by the cost of facilities to serve Hoku and, in fact, are benefitted by those facilities, at no cost to them," the company said.

Plainly put, the company said it now needs a break.

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"Hoku's current financial stress is not the result of negligence or ineptitude, but is the result of disturbances in the global solar and polysilcon markets," Hoku said.

However, Idaho Power said it has "gone out of its way" to accommodate Hoku by modifying its original contract and delaying implementation. But Hoku has failed to provide Idaho Power any assurance that it will meet its obligations to the power company, the PUC quoted the utility as saying.

Idaho Power said that to meet the revenue shortfall caused by Hoku's failure to pay, it may have to use some of the accelerated investment tax credits that were to go to customers. "The loss of revenue from such a large customer poses imminent financial harm, to Idaho Power's other customers, who may not receive their share of a tax benefit the commission just approved," the PUC said, repeating Idaho Power claims.

The commission's rule on customer deposits does not contain provisions for customers using deposits to pay monthly charges, Idaho Power said. Hoku owes another $1.8 million deposit that was due Dec. 31, 2011, but the utility agreed to extend it to March 2 so long as Hoku remained current on its energy payments. Because it has not done so, the utility argued, the remaining $1.8 million deposit is now due.

COMPANIES REFERENCED IN THIS ARTICLE:

HOKU Scientific Inc

IDACORP Inc. **IDA**

Idaho Power Co.

PR: Hoku Materials Files Complaint Against Idaho Power to Amend Electric Service Agreement

Regulatory Filing: HOKU Scientific Inc

Industry Document: Oral Argument is Jan. 11 on Hoku Complaint

Regulatory Filing: Idaho Power Co.

E-mail this story.

EPA *continued*

emission standards." The case is Sierra Club v. U.S. Environmental Protection Agency (Civil Action No. 11-1278).

Some industry observers speculate that without the stay, the EPA may be under more pressure to finalize the rules. According to the Sierra Club, existing facilities that operate industrial boilers will still have until 2014 or 2015 to reduce their emissions, as had been proposed. The EPA estimates that more than 200,000 boilers will be covered by the rules, with about 5,500 of the boilers, most of which are at industrial facilities, subject to emission limits.

Sierra Club spokesman John Coequyt said the reason why his group filed a lawsuit against the EPA was because it did not believe the agency had the right to block a rule indefinitely. "As a precedent, we couldn't let that stand," Coequyt said Jan. 11. He added that he thinks the EPA will finalize the rules by the middle of the summer.

The boiler MACT rule and the CISWI rule were slated to take effect May 20, 2011. But two days prior to the rules' enactment, the EPA issued a delay notice staying the effective date of both rules, the court noted. The EPA moved to delay the rules after facing a legal onslaught by both environmental and industry groups and after the agency sought to reconsider the rules and obtain additional public comment. The delay was subsequently challenged by the Sierra Club on July 14, 2011, on the grounds that it was unlawful to suspend them.

While industry has applauded the agency's efforts to seek additional input on the rules and embraced the agency's proposed revisions it made in December 2011, the regulations nevertheless remain a lightning rod for controversy.

"The court's ruling to revoke the stay of the boiler MACT and incinerator rules will severely harm manufacturers' competitiveness, add to their uncertainty and cost vital jobs," National Association of Manufacturers Vice President for Energy and Resources Policy Chip Yost said in a Jan. 10 statement. NAM, one of the most powerful trade associations in Washington, and other industry advocates have urged Congress to pass legislation to effectively roll back or weaken such regulations, citing the compliance costs and stringency of the standards.

The Sierra Club, on the other hand, cheered the decision, highlighting the health benefits. "The health protections will save thousands of lives every year by reducing the major amounts of toxic air pollution such as mercury, lead, arsenic and chromium that these plants emit," Coequyt said.

The EPA said the cost of implementing the standards will be about $1.5 billion less than the cost under the previous standards proposed in April 2010. The new proposed standards also will preserve health benefits that are estimated to be valued at as much as $67 billion in 2015.

Industry Document: Opinion

Industry Document: Manufacturers: Court Ruling on Boiler MACT Stay will Cost Jobs

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Colo. PUC *continued*

would be subject to refund in the unlikely event the PUC granted less than the utility requested as a final decision in the general rate case. Further, Xcel Energy said it would probably have collected only about half of the $100 million requested, as it would have taken an entire year to reach that sum with the interim rates requested.

Finally, Xcel Energy said the PUC would send an important signal to investors that the PUC is standing behind the utility in its efforts to maintain long-term financial health. Interim rate relief would have been an important step in addressing regulatory lag in revenues following expenditures, the company said.

Yet the PUC sided with the Colorado Office of Consumer Counsel, which said the company was not in dire financial straits and therefore did not need interim relief.

The utility's full rate proposal would increase monthly bills by $4.01, or 5.99%, for residential customers using an average of 632 kWh per month. Monthly bills for commercial customers using 1,123 kWh per month would rise by $5.30, or 4.83%, the PUC said.

Xcel Energy is identified for regulatory purposes as Public Service Co. of Colorado in that state.

COMPANIES REFERENCED IN THIS ARTICLE:

Public Service Co. of Colorado

Xcel Energy Inc. **XEL**

Industry Document: PUC Denies Xcel Energy Request for Interim Rate Hike

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Market Story

Midwest, Texas spot power prices advance; Northeast, West Coast values ease

by Amanda Luhavalja

Next-day power prices across the U.S. saw another varied session Wednesday, Jan. 11, as mixed load outlooks and an ongoing bearish tenor to natural gas markets all influenced spot electricity values.

In the natural gas arena, following a 9.6-cent decline Jan. 10 and continuing to wallow near lows not seen since September 2009, the front-month February contract extended lower Wednesday, settling at $2.774/MMBtu, down 16.7 cents. The ongoing weakness in futures applied pressure to physical gas markets, which in turn offered pressure at many regional power markets.

In terms of supply, about 39,200 MW is offline across the U.S., up about 6,000 MW since Jan. 10, with coal-based generation accounting for the largest share of the downed units, with about 13,400 MW offline, according to IIR Energy.

Midwest spot power prices move higher with rising demand

Despite tumbling spot gas markets around the region, spot power prices in the Midwest moved higher at midweek, with gains supported by rising demand outlooks sparked by colder temperatures.

In the Midwest, the AEP region in Ohio could see demand crest near 18,043 MW on Thursday, little changed from Wednesday, while in ComEd near Chicago, load is seen peaking near 13,950 MW on Thursday, up about 1,300 MW from Wednesday.

In PJM, on-peak power at AEP-Dayton traded in the low to mid-$30s, up about $1 on the day, with Northern Illinois hub packages reported in the low $30s, up about $2. Deals at the Indiana hub were inked in the low $30s, gaining more than $2.

Texas power prices advance with increasing demand

Shrugging off sliding cash gas markets, next-day power prices advanced several dollars in Texas, garnering support from higher demand outlooks for the second half of the workweek.

On-peak power parcels at ERCOT North and South were completed in the low $30s, increasing $4 to $5 on average on the session. ERCOT Houston deals were seen in the low $30s, as well, also increasing about $4 on the day.

The upswing in regional power prices was driven by rising demand projections. The ERCOT grid operator expects demand to peak near 42,800 MW on Thursday, up more than 2,100 MW from Wednesday.

West Coast power values retreat with revised product offering

West Coast power prices were on the downturn at midweek as weaker regional spot gas markets and lower demand outlooks ahead of the weekend weighed on prices. To account for the closure of many financial markets Jan. 16 for the Martin Luther King Jr. holiday, West Coast deals were completed Wednesday for Jan. 12-13 delivery.

In California, heavy-load deals at North Path-15 and South Path-15 traded in the upper $20s to low $30s, down about 50 cents on the day. Light-load parcels ran in the low $20s at both markets.

In the Northwest, heavy-load deals at Mid-Columbia traded in the upper $20s, easing about 25 cents, while heavy-load parcels at COB were transacted in the upper $20s to low $30s, down about 75 cents. Light-load parcels were inked a few dollars lower at both locations in the mid- to high $20s.

With the ongoing downturn in futures, forward markets in the Northwest continued to sink. February packages at Mid-C were marked near $26 to $26.50, with March deals eyed at $25.50.

In the Southwest, heavy-load packages at Mead and Palo Verde were transacted in the high $20s to low $30s, faltering 75 cents to more than $1, respectively. Light-load business at both markets was assessed from $22 to nearly $24.

Northeast power prices mostly lower with falling spot gas

With regional spot gas markets losing more than 30 cents at some locations and slightly lower load outlooks, most spot power prices in the Northeast were aimed to the downside Wednesday. On-peak power deals at the NEPOOL-Mass hub were inked in the mid-$30s, down $4 on the day, with the off-peak markets pegged in the low $30s. In New York at Zone A, spot power parcels were seen in the low $30s, easing 75 cents to $1, while at Zone G, next-day power traded in the high $30s, falling more than $1.

However, to the south, in the mid-Atlantic, PJM West on-peak spot power was transacted in the mid-$30s, up about 50 cents on the day. Off-peak PJM west was quoted in the high $20s. With the retreat in futures, term prices in PJM West eased. February parcels ran near $39, with March-April packages seen near $37 to $37.25.

Looking at load, demand in the mid-Atlantic is seen as mixed. Load in the PJM Western region is expected to reach a high near 55,802 MW on Thursday, up more than 1,400 MW from Wednesday, while demand in the Mid-Atlantic region is seen peaking near 36,653 MW on Thursday, down about 2,000 MW from Wednesday.

To the north, demand is expected to ease, with New England load called to crest near 18,460 MW on Thursday, down about 150 MW from the day prior. New York demand is seen easing to 21,050 MW on Thursday, down about 1,000 MW from the day prior.

While demand is aimed lower in the near term, colder weather is on the horizon for the region. In fact, according to AccuWeather.com, "Winter is in the process of making a comeback across the eastern two-thirds of the U.S. with a far-reaching blast of colder air and the return of substantial snow in the works."

Market prices are current as of the time of publication and are subject to change.

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Energy Pricing Trends

Peak Electricity Index (Day Ahead prices for Delivery on Jan 12, 12)

Delivery Point	Volume Wgtd. Average ($/MWh)	Change From Jan 11, 12 ($/MWh)	Volume Wgtd. Average %△ 1 Day	Volume Wgtd. Average %△ 1 Year	Trade ($/MWh) Median	Trade ($/MWh) Low	Trade ($/MWh) High	Trading Volume (MWh)	All Peak Hours Volume (MWh)
MIDWEST									
A.D.	33.50	1.00	3.08	-37.96	-	-	-	-	-
Cinergy	31.50	0.25	0.80	-38.24	-	-	-	-	-
Michigan	33.75	1.25	3.85	-34.15	-	-	-	-	-
Minnesota	28.00	2.00	7.69	-36.36	-	-	-	-	-
N. Illinois (CE)	31.75	1.75	5.83	-38.35	-	-	-	-	-
NORTHEAST									
NY Zone A	33.00	-0.75	-2.22	-37.14	-	-	-	-	-
NY Zone G	39.00	-1.75	-4.29	-42.22	-	-	-	-	-
NY Zone J	43.75	0.50	1.16	-51.39	-	-	-	-	-
Nepool-Mass	37.00	-4.00	-9.76	-52.26	-	-	-	-	-
Ontario	24.25	0.25	1.04	-46.70	-	-	-	-	-
PJM West	35.11	0.46	1.33	-50.20	35.25	35.00	35.30	500	8,000
OTC BROKER									
Broker ERCOT-Hou.	31.50	4.25	15.60	-31.52	31.50	31.50	31.50	500	8,000
Broker ERCOT-North	31.37	4.27	15.76	-33.00	31.28	31.00	31.75	1,850	29,600
Broker ERCOT-S.C.	-	-	-	-	-	-	-	-	-
Broker ERCOT-South	31.25	4.50	16.82	-29.52	-	-	-	-	-
Broker ERCOT-West	31.40	1.15	3.80	-32.11	-	-	-	-	-
SOUTH									
ERCOT-Hou.	31.50	4.03	14.67	-31.15	31.50	31.50	31.50	50	800
ERCOT-North	31.43	4.37	16.15	-33.07	31.38	31.00	32.00	1,600	25,600
ERCOT-NE	-	-	-	-	-	-	-	-	-
ERCOT-S.C.	-	-	-	-	-	-	-	-	-
ERCOT-South	31.25	4.50	16.82	-29.78	31.25	31.25	31.25	50	800
ERCOT-West	31.40	1.15	3.80	-32.11	31.40	31.40	31.40	50	800
Entergy	27.00	2.75	11.34	-41.30	-	-	-	-	-
Fla. In-State	28.25	2.75	10.78	-51.91	-	-	-	-	-
Fla.-Ga. Bdr.	27.50	-0.25	-0.90	-56.69	-	-	-	-	-
Southern	27.25	2.00	7.92	-47.09	-	-	-	-	-
WEST									
COB	30.00	-0.50	-1.64	-14.77	30.00	30.00	30.00	90	1,440
Mead	30.12	-1.02	-3.28	-17.48	30.00	30.00	30.35	75	1,200
Mid-C	30.13	1.30	4.51	-4.74	30.13	30.00	30.25	50	800
NP-15	30.00	-1.50	-4.76	-19.46	-	-	-	-	-
Palo Verde	28.75	-1.17	-3.91	-19.08	28.75	28.75	28.75	50	800
SP-15	29.75	-1.75	-5.56	-19.59	-	-	-	-	-

Off-Peak Electricity Index (Day Ahead prices for Delivery on Jan 12, 12)

Delivery Point	Volume Wgtd. Average ($/MWh)	Change From Jan 11, 12 ($/MWh)	Volume Wgtd. Average %△ 1 Day	Volume Wgtd. Average %△ 1 Year	Trade ($/MWh) Median	Trade ($/MWh) Low	Trade ($/MWh) High	Trading Volume (MWh)
OTC BROKER								
Broker ERCOT-North	23.50	2.00	9.30	-36.49	23.50	23.50	23.50	50
SOUTH								
ERCOT-North	22.93	1.70	8.01	-38.14	22.88	22.70	23.55	650
WEST								
Mid-C	26.44	0.44	1.69	-4.93	26.25	26.00	27.00	225
Palo Verde	21.58	-0.30	-1.37	-16.19	21.70	21.25	21.75	200

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Energy Pricing Trends *continued*

Gas Index (Day Ahead prices for Delivery on Jan 12, 12)

Trading Hub	Volume Wgtd. Average ($/mmBtu)	Change From Jan 11, 12 ($/mmBtu)	Volume Wgtd. Average %△ 1 Day	Volume Wgtd. Average %△ 1 Year	Trade ($/mmBtu) Median	Trade ($/mmBtu) Low	Trade ($/mmBtu) High	Trading Volume (mmBtu)
GULF COAST								
ANR-Patterson (LA)	2.792	-0.139	-4.74	-36.05	2.790	2.770	2.810	93,100
Agua Dulce	2.790	-0.140	-4.78	-36.01	-	-	-	-
Carthage	2.759	-0.126	-4.37	-36.18	2.770	2.750	2.780	13,500
Col Gulf Mainline	2.773	-0.155	-5.29	-36.66	2.780	2.750	2.790	115,901
Col Gulf Onshore	2.790	-0.156	-5.30	-35.94	2.780	2.750	2.810	110,900
FGT Zone 2	2.830	-0.160	-5.35	-36.12	-	-	-	-
FGT Zone 3	2.849	-0.152	-5.06	-37.30	2.860	2.790	2.880	27,600
FGT Zone 1	2.810	-0.160	-5.39	-36.14	-	-	-	-
Henry Hub	2.808	-0.168	-5.65	-36.40	2.810	2.800	2.830	120,800
Houston Ship Channel	2.810	-0.200	-6.64	-34.39	2.820	2.790	2.850	20,900
Katy	2.817	-0.141	-4.77	-35.30	2.820	2.790	2.825	169,400
Moss Bluff	2.800	-0.195	-6.51	-35.42	2.800	2.800	2.800	10,000
NGPL Gulf Line	2.790	-0.180	-6.06	-36.01	-	-	-	-
NGPL Louisiana	2.760	-0.180	-6.12	-37.70	-	-	-	-
NGPL South TX	2.771	-0.096	-3.35	-35.92	2.775	2.750	2.785	24,200
Sonat	2.811	-0.152	-5.13	-36.85	2.810	2.795	2.825	150,700
Stingray	2.700	-0.150	-5.26	-44.10	-	-	-	-
TETCO M2	2.913	-0.172	-5.58	-37.98	2.915	2.830	3.010	76,500
TETCO M1 (24-inch)	2.878	-0.152	-5.02	-35.64	2.820	2.810	2.960	24,300
TETCO M1 (30-inch)	2.817	-0.146	-4.93	-37.08	2.820	2.765	2.960	66,519
TX Eastern (E. LA)	2.795	-0.164	-5.54	-36.41	2.790	2.790	2.800	28,500
TX Eastern (E. TX)	2.710	-0.100	-3.56	-37.56	-	-	-	-
TX Eastern (S. TX)	2.787	-0.120	-4.13	-35.86	2.780	2.780	2.800	30,000
TX Eastern (W. LA)	2.782	-0.125	-4.30	-35.94	2.780	2.775	2.800	36,300
Tennessee Zone 0	2.753	-0.148	-5.10	-36.55	2.750	2.745	2.760	81,900
Tennessee Zone 1	2.799	-0.161	-5.44	-36.10	2.800	2.770	2.820	379,400
Texas Gas (LA)	2.751	-0.194	-6.59	-36.86	2.758	2.750	2.765	11,000
Texas Gas (Zone 1)	2.764	-0.167	-5.70	-36.72	2.762	2.750	2.785	57,500
Transco Z 5	3.005	-0.165	-5.21	-73.22	3.005	3.005	3.005	14,037
Transco Z 1	2.735	-0.131	-4.57	-37.27	2.738	2.730	2.740	22,200
Transco Z 3	2.819	-0.151	-5.08	-36.11	2.814	2.770	2.838	189,941
Transco Z 4	2.821	-0.160	-5.37	-36.32	2.820	2.785	2.860	146,043
Transco Z2	2.773	-0.148	-5.07	-36.69	2.770	2.770	2.780	9,100
Trunkline (E. LA)	2.811	-0.117	-4.00	-35.08	2.768	2.710	3.070	47,900
Trunkline (W. LA)	2.797	-0.122	-4.18	-35.92	2.800	2.790	2.800	14,800
Trunkline Zone 1A	2.784	-0.142	-4.85	-36.45	2.785	2.773	2.800	49,900
MID-CONTINENT								
ANR-ML7	3.025	-0.065	-2.10	-35.50	2.940	2.930	3.040	23,400
ANR-SW	2.785	-0.198	-6.64	-36.05	2.782	2.770	2.800	33,600
Alliance	2.966	-0.163	-5.21	-35.56	2.963	2.950	2.990	80,000
Centerpoint East	2.745	-0.158	-5.44	-37.31	2.763	2.723	2.788	60,000
Centerpoint No/So	2.750	-0.140	-4.84	-37.78	-	-	-	-
Centerpoint West	2.760	-0.140	-4.83	-36.99	-	-	-	-
Chicago	2.962	-0.154	-4.94	-35.40	2.958	2.805	2.995	356,700
Cons Energy Citygate	2.984	-0.159	-5.06	-35.23	2.980	2.955	3.015	91,300
Delivery So. Star	2.760	-0.220	-7.38	-36.67	2.750	2.730	2.770	26,700
Emerson	3.032	-0.176	-5.49	-32.47	3.030	3.010	3.070	188,600
Enogex E Zone Pool	3.120	-0.270	-7.96	-30.97	-	-	-	-
Enogex W Zone Pool	2.780	-0.190	-6.40	-36.02	2.780	2.780	2.780	8,000
Michcon Detroit CG	2.988	-0.171	-5.41	-34.73	2.985	2.965	3.015	188,282
NGPL Amarillo	2.833	-0.207	-6.81	-35.61	2.833	2.820	2.845	9,800
NGPL Forgan, OK	2.767	-0.185	-6.27	-36.33	2.763	2.750	2.800	251,654
NGPL Tex/Ok	2.779	-0.180	-6.08	-35.63	2.780	2.760	2.793	123,900
NNG Demarc	2.914	-0.150	-4.90	-36.07	2.910	2.880	2.930	125,127
NNG Ventura	2.916	-0.179	-5.78	-35.98	2.912	2.860	2.935	524,155
Northern Mid-10	2.810	-0.130	-4.42	-36.57	-	-	-	-
ONG at Tulsa	2.720	-0.168	-5.82	-37.90	-	-	-	-
PEPL	2.762	-0.231	-7.72	-36.65	2.760	2.740	2.910	133,429
Rex East	2.918	-0.158	-5.14	-36.06	2.920	2.900	2.930	136,200

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Energy Pricing Trends *continued*

Gas Index (Day Ahead prices for Delivery on Jan 12, 12) *continued*

Trading Hub	Volume Wgtd. Average ($/mmBtu)	Change From Jan 11, 12 ($/mmBtu)	Volume Wgtd. Average %△ 1 Day	Volume Wgtd. Average %△ 1 Year	Trade ($/mmBtu) Median	Trade ($/mmBtu) Low	Trade ($/mmBtu) High	Trading Volume (mmBtu)
NORTHEAST								
Algon Gates	3.816	-0.836	-17.97	-57.65	3.850	3.700	4.150	57,934
Algonquin PA-NJ	3.780	-0.757	-16.69	-58.17	3.835	3.700	4.150	69,234
Dawn, Ont.	3.184	-0.178	-5.29	-33.56	3.183	3.110	3.215	263,300
Dominion S	2.789	-0.194	-6.50	-39.80	2.790	2.770	2.800	160,771
Dominion N	2.795	-0.202	-6.74	-39.37	2.799	2.790	2.808	3,500
Iroquois Waddington	3.698	-0.468	-11.23	-37.22	3.690	3.560	3.730	74,900
Iroquois Z 2	3.774	-0.341	-8.29	-62.26	3.760	3.680	3.870	29,200
Lebanon	2.870	-0.180	-5.90	-37.31	2.875	2.863	2.880	21,000
Leidy	2.914	-0.209	-6.69	-42.29	2.920	2.850	2.943	90,189
Natl Fuel Gas NY-PA	3.420	-0.520	-13.20	-62.46	-	-	-	-
Niagara	3.228	-0.199	-5.81	-36.09	3.230	3.180	3.260	33,970
TCO pool	2.849	-0.165	-5.47	-37.47	2.847	2.830	2.870	49,370
Tennessee Zone 5	3.840	-0.650	-14.48	-58.22	-	-	-	-
Tennessee Zone 6	3.854	-0.658	-14.58	-57.02	3.885	3.800	3.990	126,065
Tennessee at Dracut	3.790	-0.800	-17.43	-55.50	-	-	-	-
Tetco M-3	3.067	-0.163	-5.05	-66.47	3.058	3.040	3.110	194,513
Transco Z 6 NY	3.166	-0.311	-8.94	-72.90	3.150	3.140	3.240	223,469
Transco Z 6 non-NY	2.991	-0.129	-4.13	-73.74	3.010	2.900	3.035	47,900
WEST								
AECO Storage Hub	2.568	-0.112	-4.18	-31.06	2.578	2.510	2.585	554,435
CIG, Rocky Mountains	2.749	-0.178	-6.08	-35.01	2.745	2.740	2.760	20,200
Cheyenne Hub	2.775	-0.221	-7.38	-35.31	2.773	2.770	2.790	17,600
El Paso - S Mainline	3.151	-0.132	-4.02	-27.45	3.155	3.140	3.160	29,200
El Paso - Waha Pool	2.806	-0.164	-5.52	-33.55	2.815	2.780	2.830	7,800
El Paso Bondad	2.800	-0.217	-7.19	-33.01	2.800	2.800	2.800	1,300
El Paso Permian	2.814	-0.161	-5.41	-33.40	2.815	2.790	2.820	109,400
El Paso SJ	3.019	0.000	0.00	-28.14	2.840	2.800	3.245	262,100
Empress	2.156	-0.135	-5.89	-40.08	2.150	2.125	2.180	218,335
Houston Pipeline	2.830	-0.130	-4.39	-33.88	-	-	-	-
Kern River	2.866	-0.155	-5.13	-31.92	2.870	2.840	2.870	19,000
Kern River Station	3.055	-0.155	-4.83	-29.72	3.055	3.055	3.055	1,400
Kingsgate	2.901	-0.140	-4.60	-31.52	2.903	2.895	2.910	25,000
NW Dom.-SJ Basin	2.850	-0.170	-5.63	-32.94	-	-	-	-
NW Opal, WY	2.859	-0.167	-5.52	-32.01	2.865	2.840	2.880	56,300
NW Stanfield, OR	2.964	-0.139	-4.48	-29.43	2.964	2.950	2.970	86,614
NW Sumas	3.115	0.028	0.91	-26.18	3.085	3.055	3.245	25,000
NW-S of Green River	2.780	-0.200	-6.71	-33.49	-	-	-	-
NoCal Border-Malin	2.958	-0.172	-5.50	-30.89	2.958	2.955	2.960	28,700
PG&E Gate	3.239	-0.142	-4.20	-26.35	3.238	3.220	3.255	514,000
PG&E South	3.069	-0.161	-4.98	-28.73	3.068	3.050	3.080	138,700
Questar	2.848	-0.172	-5.70	-32.67	2.850	2.840	2.850	12,200
Rex West	2.750	-0.150	-5.17	-37.78	-	-	-	-
SoCal Border	3.106	-0.120	-3.72	-28.10	3.118	3.050	3.160	189,600
SoCal Citygate	3.158	-0.153	-4.62	-27.02	3.160	3.150	3.170	572,500
TransW E of Thoreau	2.783	-0.160	-5.44	-34.59	2.780	2.770	2.800	11,000
Waha Hub	2.821	-0.136	-4.60	-34.24	2.820	2.800	2.825	14,300
West Coast Sta. 2	2.427	-0.122	-4.79	-26.88	2.425	2.420	2.445	27,000

Additional delivery points and other energy pricing information are available at http://www.snl.com/interactivex/marketdata.aspx.

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SNL Gas Spark Spread

Day ahead Prices for Delivery Jan 11, 12

Gas Location	Power Location	Gas Avg. ($/mmBtu)	Power Avg. ($/MWH)	Spark Spreads at Various Heat Rates ($) 7,000	8,000	10,000	12,000	14,000	Implied Heat Rate
TCO pool	Cinergy	3.01	31.25	10.15	7.14	1.11	-4.92	-10.95	10,368.28
Henry Hub	Entergy	2.98	24.25	3.42	0.44	-5.51	-11.46	-17.41	8,148.52
NW Sumas	Mid-C	3.09	28.83	7.22	4.13	-2.04	-8.21	-14.39	9,339.16
NNG Demarc	Minnesota	3.06	26.00	4.55	1.49	-4.64	-10.77	-16.90	8,485.64
Chicago	N. Illinois (CE)	3.12	30.00	8.19	5.07	-1.16	-7.39	-13.62	9,627.73
Algon Gates	Nepool-Mass	4.65	41.00	8.44	3.78	-5.52	-14.82	-24.13	8,813.41
PG&E Gate	NP-15	3.38	31.50	7.83	4.45	-2.31	-9.07	-15.83	9,316.77
Niagara	NY Zone A	3.43	33.75	9.76	6.33	-0.52	-7.37	-14.23	9,848.26
Iroquois Z 2	NY Zone G	4.12	40.75	11.95	7.83	-0.40	-8.63	-16.86	9,902.79
Transco Z 6 NY	NY Zone J	3.48	43.25	18.91	15.43	8.48	1.53	-5.43	12,438.88
Dawn, Ont.	Ontario	3.36	24.00	0.47	-2.90	-9.62	-16.34	-23.07	7,138.61
El Paso SJ	Palo Verde	3.02	29.92	8.79	5.77	-0.27	-6.31	-12.35	9,910.57
Tetco M-3	PJM West	3.23	34.65	12.04	8.81	2.35	-4.11	-10.57	10,727.55
SoCal Border	SP-15	3.23	31.50	8.92	5.69	-0.76	-7.21	-13.66	9,764.41

Forward Power Deals ($/MWh)

For the period Jan 11, 12

Electricity delivery point	Term	Volume wgtd. average ($/MWh)	Low trade ($/MWh)	High trade ($/MWh)	Trading volume reported (MW)
		PEAK			
		Northeast			
Nepool-Mass	Jan 16, 12-Jan 20, 12	56.50	56.50	56.50	50
Nepool-Mass	Jan 23, 12-Jan 27, 12	47.50	47.25	48.00	150
Nepool-Mass	Jul 01, 12-Aug 31, 12	45.50	45.50	45.50	50
NY Zone G	Mar 01, 12-Mar 31, 12	41.25	41.25	41.25	50
PJM West	Jan 13, 12-Jan 13, 12	39.75	39.25	40.25	500
PJM West	Jan 16, 12-Jan 16, 12	42.00	42.00	42.00	50
PJM West	Feb 01, 12-Dec 31, 12	40.11	40.10	40.12	200
PJM West	Mar 01, 12-Mar 31, 12	37.30	37.30	37.30	100
PJM West	Apr 01, 12-Apr 30, 12	37.10	37.10	37.10	50
PJM West	Jan 01, 13-Dec 31, 13	43.05	43.05	43.05	50
PJM West	Jan 01, 14-Dec 31, 14	45.66	45.55	45.75	200
		South			
ERCOT-North	Jan 13, 12-Jan 31, 12	27.70	27.70	27.70	150
ERCOT-North	Jan 16, 12-Jan 20, 12	26.25	26.25	26.25	100
		OFF-PEAK			
		Northeast			
PJM West	Apr 01, 12-Apr 30, 12	28.75	28.75	28.75	50
PJM West	Jun 01, 12-Jun 30, 12	28.95	28.90	29.00	100

Nuclear Outage Report

For the period Jan 11, 12

Unit	Operator	State	Current power level (%)	Previous power level (%)	Nameplate capacity (MW)
H B Robinson PWR 2	Carolina Power & Light Co.	SC	90	91	768.6
Indian Point 2 PWR 2	Entergy Nuclear Indian Po	NY	0	36	1,299.0
Oyster Creek BWR 1	Exelon Power	NJ	90	100	550.0
Seabrook PWR 1	NextEra Energy	NH	72	71	1,242.0

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Dominion Energy Index

Day	Date	Forecast or Actual Index	Above/Below Normal △	Above/Below Normal △%
UNITED STATES				
Tuesday	Jan 10, 12	24.7	-14.8	-37.5
Wednesday	Jan 11, 12	24.7	-14.8	-37.5
Thursday	Jan 12, 12	28.0	-11.7	-29.4
Friday	Jan 13, 12	33.5	-6.4	-16.1
Saturday	Jan 14, 12	37.5	-2.4	-6.1
Sunday	Jan 15, 12	37.8	-2.3	-5.7
Monday	Jan 16, 12	34.4	-5.8	-14.5
Tuesday	Jan 17, 12	33.2	-7.1	-17.6
GREAT LAKES				
Tuesday	Jan 10, 12	33.8	-29.0	-46.2
Wednesday	Jan 11, 12	33.4	-29.7	-47.1
Thursday	Jan 12, 12	40.3	-23.0	-36.4
Friday	Jan 13, 12	53.6	-10.4	-16.3
Saturday	Jan 14, 12	63.0	-1.3	-2.1
Sunday	Jan 15, 12	58.9	-6.2	-9.5
Monday	Jan 16, 12	52.3	-13.2	-20.1
Tuesday	Jan 17, 12	51.5	-13.3	-20.6
GREAT PLAINS				
Tuesday	Jan 10, 12	31.4	-32.9	-51.1
Wednesday	Jan 11, 12	39.7	-23.8	-37.5
Thursday	Jan 12, 12	58.0	-5.3	-8.4
Friday	Jan 13, 12	60.7	-2.4	-3.8
Saturday	Jan 14, 12	56.5	-6.6	-10.5
Sunday	Jan 15, 12	48.2	-14.9	-23.6
Monday	Jan 16, 12	44.2	-18.9	-29.9
Tuesday	Jan 17, 12	48.3	-14.9	-23.6
LOWER MISSISSIPPI				
Tuesday	Jan 10, 12	13.5	-17.9	-57.0
Wednesday	Jan 11, 12	10.9	-20.8	-65.5
Thursday	Jan 12, 12	25.2	-6.9	-21.4
Friday	Jan 13, 12	37.4	5.2	16.1
Saturday	Jan 14, 12	36.1	3.8	11.8
Sunday	Jan 15, 12	30.2	-2.2	-6.7
Monday	Jan 16, 12	23.6	-8.7	-27.0
Tuesday	Jan 17, 12	18.8	-13.7	-42.2
MID-ATLANTIC				
Tuesday	Jan 10, 12	33.1	-15.8	-32.3
Wednesday	Jan 11, 12	31.4	-17.8	-36.2
Thursday	Jan 12, 12	23.3	-26.1	-52.9
Friday	Jan 13, 12	30.7	-19.0	-38.3
Saturday	Jan 14, 12	42.1	-7.9	-15.9
Sunday	Jan 15, 12	52.7	2.4	4.8
Monday	Jan 16, 12	51.6	0.6	1.2
Tuesday	Jan 17, 12	43.2	-8.1	-15.8
NEW ENGLAND				
Tuesday	Jan 10, 12	38.7	-16.8	-30.3
Wednesday	Jan 11, 12	38.1	-17.7	-31.8
Thursday	Jan 12, 12	39.3	-16.7	-29.8
Friday	Jan 13, 12	34.8	-21.6	-38.3
Saturday	Jan 14, 12	41.5	-15.4	-27.0
Sunday	Jan 15, 12	58.5	1.3	2.3
Monday	Jan 16, 12	61.3	3.5	6.1
Tuesday	Jan 17, 12	51.8	-6.6	-11.3
PACIFIC				
Tuesday	Jan 10, 12	23.9	-.9	-3.8
Wednesday	Jan 11, 12	24.7	0.1	0.3
Thursday	Jan 12, 12	26.0	1.6	6.5
Friday	Jan 13, 12	25.2	1.1	4.4
Saturday	Jan 14, 12	25.5	1.5	6.4
Sunday	Jan 15, 12	26.6	2.9	12.3
Monday	Jan 16, 12	28.9	5.4	22.9
Tuesday	Jan 17, 12	31.2	7.9	33.9
ROCKY MOUNTAINS				
Tuesday	Jan 10, 12	35.8	-15.7	-30.5
Wednesday	Jan 11, 12	53.9	2.2	4.3
Thursday	Jan 12, 12	56.7	5.0	9.7
Friday	Jan 13, 12	51.3	-0.5	-1.0
Saturday	Jan 14, 12	44.0	-7.8	-15.1
Sunday	Jan 15, 12	38.1	-13.8	-26.6
Monday	Jan 16, 12	39.6	-12.3	-23.7
Tuesday	Jan 17, 12	46.4	-5.6	-10.8
SOUTH ATLANTIC				
Tuesday	Jan 10, 12	18.5	-11.7	-38.8
Wednesday	Jan 11, 12	17.7	-12.7	-41.8
Thursday	Jan 12, 12	15.7	-14.8	-48.5
Friday	Jan 13, 12	21.1	-9.4	-30.9
Saturday	Jan 14, 12	28.2	-2.2	-7.2
Sunday	Jan 15, 12	29.2	-1.1	-3.5
Monday	Jan 16, 12	28.3	-1.9	-6.4
Tuesday	Jan 17, 12	27.3	-2.9	-9.7
SOUTHWEST				
Tuesday	Jan 10, 12	12.4	-1.5	-10.9
Wednesday	Jan 11, 12	9.9	-3.9	-28.4
Thursday	Jan 12, 12	15.9	1.8	13.0
Friday	Jan 13, 12	18.2	4.0	28.2
Saturday	Jan 14, 12	16.9	2.9	20.7
Sunday	Jan 15, 12	13.0	-0.9	-6.5
Monday	Jan 16, 12	4.5	-9.2	-67.1
Tuesday	Jan 17, 12	8.2	-5.4	-39.5

The Dominion Energy Index, maintained by The Dominion Energy Services Corp., measures actual and forecast demand for heating and cooling energy. It is designed to be more precise than the current heating degree days and cooling degree days indexes. The first reading in each regional list is the actual energy demand measured the day the forecast is made. The forecast energy demand for the following week for a given region follows the actual reading in the table. "Normals" for each region for each day have been calculated using 30-year weather averages.

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NYMEX Natural Gas Futures

For the period Jan 11, 12

Contract	Prior Settle ($/mmBtu)	High ($/mmBtu)	Low ($/mmBtu)	Settle ($/mmBtu)	Change ($/mmBtu)
Feb-2012	2.941	3.045	2.903	2.774	-0.167
Mar-2012	2.970	3.082	2.937	2.803	-0.167
Apr-2012	3.042	3.147	3.006	2.883	-0.159
May-2012	3.103	3.204	3.065	2.949	-0.154
Jun-2012	3.158	3.253	3.120	3.004	-0.154
Jul-2012	3.214	3.311	3.177	3.060	-0.154
Aug-2012	3.240	3.332	3.206	3.086	-0.154
Sep-2012	3.244	3.336	3.206	3.091	-0.153
Oct-2012	3.281	3.374	3.247	3.131	-0.150
Nov-2012	3.430	3.510	3.399	3.295	-0.135
Dec-2012	3.696	3.771	3.662	3.580	-0.116
Jan-2013	3.825	3.897	3.789	3.717	-0.108
Feb-2013	3.824	3.894	3.793	3.715	-0.109
Mar-2013	3.797	3.845	3.765	3.691	-0.106
Apr-2013	3.764	3.824	3.734	3.658	-0.106
May-2013	3.786	3.851	3.759	3.680	-0.106
Jun-2013	3.816	3.822	3.800	3.711	-0.105
Jul-2013	3.860	3.929	3.840	3.755	-0.105

Changes in settlement price with zero volume mean the settlement price is implied. No actual trading took place for these contracts on the given day. Price is based on delivery at the Henry Hub in Louisiana, which serves markets throughout the U.S. East Coast, the Gulf Coast, the Midwest, and up to the Canadian border.

SNL Daily OTC Coal and Emissions Assessments

Jan 11, 12 Product	Price ($/ton)	Change (%) 1 day	Change (%) 1 week
NYMEX Big Sandy			
February 2012	64.98	-2.65	-6.17
Q2 2012	65.13	-2.72	-6.40
CSX/Rail			
February 2012	63.75	-2.64	-6.36
Q2 2012	63.75	-2.60	-6.70
PRB 8,800			
February 2012	11.23	-2.52	-8.55
Q2 2012	11.13	-2.20	-9.88
PRB 8,400			
February 2012	9.50	-4.33	-7.32
Q2 2012	9.75	-2.01	-6.70

Jan 11, 12 Product	Price ($/credit)	Change (%) 1 day	Change (%) 1 week
SO2			
2010	1.63	0.00	-18.50
2011	1.38	0.00	-31.00
2012	1.38	0.00	0.00
2013	0.81	0.00	-28.32
2014	0.81	0.00	-28.32
2015	0.81	0.00	-28.32
NOx			
2012	25.00	0.00	488.24

Data provided by Evolution Markets and Amerex Brokers

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SNL RECs Index

Week ending 01/06/12

Product	Term	Price	Product	Term	Price	Product	Term	Price
CA RPS-REC	2011	2.00	MA Class I	2012	35.94	NJ Solar REC	2011	NA
CA RPS-REC	11-13	2.38	MA Class I	2013	36.04	NJ Solar REC	2012	291.25
CA RPS-REC	11-16	NA	MA Class II WTE	2011	3.33	NJ Solar REC	2013	280.00
CT Class I REC	2011	44.00	MA Solar	2011	534.38	OH Contiguous REC	2010	NA
CT Class I REC	2012	33.71	MD Solar	2010	211.67	OH In-State Solar	2011	350.00
CT Class I REC	2013	33.54	MD Solar	2011	216.25	OH Located REC	2011	11.75
CT Class II REC	2011	0.40	MD Tier I	2010	NA	PA Solar REC	2011	NA
CT Class II REC	2012	0.80	MD Tier I	2011	2.04	PA Solar REC	2012	56.25
CT Class III REC	2011	10.00	MD Tier II	2010	NA	PA Tier 1 REC	2011	1.63
CT Class III REC	2012	10.19	ME Class I	2011	15.88	PA Tier 1 REC	2012	2.03
CT Class III REC	2013	11.31	ME Class I	2012	17.25	PA Tier 2 REC	2010	NA
DC Solar REC	2011	300.00	NH Class I	2011	44.00	PA Tier 2 REC	2011	0.15
DC Tier I REC	2011	2.13	NH Class II	2011	50.00	PA Tier 2 REC	2012	0.17
DE EXISTING REC	2010	0.88	NH Class III	2011	NA	RI Existing REC	2011	0.88
DE NEW REC	2010	NA	NH Class IV	2011	NA	RI NEW REC	2011	44.00
DE NEW REC	2011	1.95	NJ Class I REC	2011	1.94	TX REC	2010	1.90
DE Solar REC	2010	82.50	NJ Class I REC	2012	2.33	TX REC	2011	1.90
MA APS	2011	NA	NJ Class I REC	2013	2.56	TX REC	2012	2.16
MA APS	2012	19.68	NJ Class II REC	2011	0.53	WA RPS	11-14	2.75
MA Class I	2011	40.97	NJ Class II REC	2012	0.68	WA RPS	15-18	4.75

Data is compiled from a range of market indicatives and do not necessarily represent completed trades. CA and WA RPS figures do not contain data from Evolution Markets.
Data for SNL RECs index provided by:
Evolution Markets: http://new.evomarkets.com/
Tradition Financial Services: http://www.tfsbrokers.com/
Clear Energy Brokerage and Consulting: http://www.clearenergybrokerage.com/
Karbone: http://www.karbone.com/
Please contact data providers for more detailed or specific transaction data or REC markets not covered by SNL index.
Source: SNL Energy

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

BOARD OF DIRECTORS MEETING

Wednesday, February 1, 2012
8:00 a.m. – Noon
10th Floor - NPCC Offices – New York, NY

Dial-In Available: 877-260-3999 **Code: 6945#**

AGENDA

1. Introductions/Quorum/Antitrust Compliance Guidelines 8:00 a.m.

2. President's Report 8:05 a.m.

3. Consideration of draft NPCC Board of Directors Minutes of November 30, 2011 Meeting 8:15 a.m. *[Action Required]*

4. Committee Reports and Work Plans 8:20 a.m.
   a) Committee Membership Changes *[Action Required]*
   b) Approval of Committee Scopes *[Action Required]*
   c) Approval of Committee Work Plans *[Action Required]*

5. 2011 Corporate Goal Attainment 9:00 a.m.
   a) MDCC Recommendations *[Action Required]*
   (Committee Resolutions to be distributed at meeting)

6. Discussion of proposed NPCC 2012 Corporate Goals 9:30 a.m.
   (Consideration by subsequent email ballot)

7. Organizational Matters 10:00 a.m.
   a) Management Development and Compensation Committee Activities
   b) NERC & Regional Entity Presidents' 2012 Strategy Session

8. NERC Matters 10:30 a.m.
   a) Remarks from NERC Trustee Jan Schori
   b) Member Representatives Committee and Board of Trustees – February 8-9, 2012 Agenda (to be distributed by NERC on January 26th, 2012)
   c) NPCC BOD Policy Input *[Action Required]*

9. Report by the Treasurer 11:20 a.m.
   a) Year End Results (unaudited)
   b) Finance and Audit Committee Activities

10. Administrative Matters 11:30 a.m.
    a) Annual Code of Conduct Implementation
    b) Office of Enforcement of FERC – Audit of NPCC

11. 2012 Board of Director Meeting Dates 11:55 p.m.
    - Tuesday, March 13, 2012 –Tentative BES Teleconference (10 a.m. – 11 a.m.)
    - Tuesday, May 1, 2012 – Teleconference (10 a.m. – 1 p.m.)
    - Tuesday, June 26, 2012 – NPCC Offices (10 a.m. – 3 p.m.)
    - Tuesday, August 7, 2012 – Teleconference (10 a.m. – 1 p.m.)
    - Wednesday, September 19, 2012 – NPCC Offices (10 a.m. – 3 p.m.)
    - Tuesday, October 30, 2012 – Teleconference (10 a.m. – 1 p.m.)
    - Wednesday, November 28, 2012 – Montreal, Quebec (7:30 a.m. – 10 a.m.)

In Camera Session

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

Northeast Power Coordinating Council, Inc. (NPCC)

Chairman: **Harvey J. Reed**
President and CEO: **Edward A. Schwerdt**
Chief Operating Officer: **Jennifer Budd Mattiello**
Secretary: **Andrianne S. Payson, Esq.**
Treasurer: **Christopher Weir, CPA**

DIRECTORS

SECTOR 1 – Transmisson Owners
William G. Longhi (O&R)
André Boulanger (HQ TE)

SECTOR 2 – Reliability Coordinators
Peter Brandien (ISO-NE)
Bruce B. Campbell (IESO)

SECTOR 3 – TDUs, Dist., LSEs
David H. Boguslawski (Northeast Utilities)
Michael Penstone (Hydro One)

SECTOR 4 – Generator Owners
Andrew Barrett (OPG)
Brad Van Auken (NYPA)

SECTOR 5 – Marketers, Brokers, Aggregators
Glen McCartney (CECG)
Daniel Whyte (Brookfield)

SECTOR 6 – State and Provincial Regulatory and/or Governmental Authorities

Hans Mertens (VT DPS)
Tammy Mitchell (NYS DPS)

SECTOR 7- Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities
Michael Forte (NYSRC)
Jeffrey Fenn – (SGC Engineering)

SECTOR 8 – Independent Directors

Donald L. Correll
Jan L. Newton

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Andrianne S. Payson at 212-259-8218.

NPCC, Inc.

President's Report

February 1, 2012

Board of Directors Meeting

NPCC, Inc.

Report Items:

- 2012 Reliability Issues
- Significant Focus Areas
- Desired Accomplishments

Northeast Power Coordinating Council, Inc. Board of Directors Meeting
Draft Minutes for Approval

November 30, 2011 | 7:35 a.m.
Toronto Marriott Bloor Yorkville, Toronto, Ontario

The Chairman called to order a duly noticed meeting of the Board of Directors ("*Board"*) of Northeast Power Coordinating Council, Inc. ("*NPCC*") held on November 30, 2011, at 7:35 a.m. A quorum was declared present during the meeting by the President and CEO, Edward Schwerdt. Andrianne Payson acted as Recording Secretary. The meeting announcement, agenda and list of attendees are attached as **Exhibits A, B, and C**, respectively.

NPCC Antitrust Compliance Guidelines

The Chairman recommended that a reading of the *NPCC Antitrust Compliance Guidelines* that were distributed via email with the Board agenda package and reviewed by Directors upon commencement of the meeting be waived. A motion to waive the reading of the *NPCC Antitrust Compliance Guidelines* was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Minutes

The President and CEO presented for approval a draft of the minutes of the Board teleconference held on October 26, 2011. A motion to approve the minutes of the NPCC Board of Directors teleconference held on October 26, 2011 was duly made, seconded and approved by the majority of Directors in each active Sector of the Board with one abstention.

Future Meetings

The President and CEO presented the schedule of Board meetings for calendar year 2012. He noted that the Board's Strategy Session would be held the afternoon of Monday, January 31, 2012 and that the first Board meeting for the year would follow the next morning on Tuesday, February 1, 2012.

President's Report

The President and CEO presented his report to the Board, which is summarized below.

Bulk Electric System – The President and CEO informed the Board that two NERC recirculation ballots, one for the Bulk Electric System ("*BES*") definition and a second for the criteria to request an exception, closed on November 21, 2011 and were approved by stakeholders. The first ballot approving the BES definition received an 81.32% affirmative vote and the second ballot approving the exception criteria received an 81.48% affirmative vote. The President and CEO noted that from an industry-wide perspective, virtually all of the Canadian "ballot" members either abstained from the vote or voted against the BES definition. He explained that the stakeholder approved BES definition, its related implementation plan and supporting application form for exception requests will be presented to the NERC Board of Trustees ("*BOT*") for adoption and subsequently filed with the regulatory authorities. He noted that the regulatory deadline in FERC Order No. 743 *Revision of the Electric Reliability Organization Definition of Bulk Electric System* and related FERC Order No. 743-A requires that the revised BES definition and the process for handling exceptions be filed by January 25, 2012. He explained that NPCC recently met with FERC senior staff to discuss any concerns that FERC may have regarding implementation of the BES definition within NPCC's geographic footprint in the United States. He further explained that NPCC's informal

meeting with FERC senior staff provided an opportunity for frank discussion and allowed for clarification of the BES exceptions regarding (i) the content of the January 25, 2012 compliance filing, (ii) the criteria for inclusions and exclusions, (iii) the procedure for identification of the new BES facilities, (iv) the process for requesting and granting exceptions, and (v) the issues that will be considered by the industry as part of Phase 2 of the BES project. The President and CEO informed the Board that NPCC faced a significant amount of work in 2012 regarding implementation of the BES definition within NPCC's Canadian Provinces.

NPCC Activities During 2011 – The President and CEO reported that there were several achievements during calendar year 2011, including (i) FERC approval of NPCC's Amended & Restated Bylaws which reflected specific enhancements in NPCC's corporate governance structure, (ii) FERC approval of the expansion of the *Regional Delegation Agreement* to incorporate NPCC's role as the Compliance Enforcement Authority for WECC's Reliability Coordinator function, (iii) the Board's direction to NPCC's Regional Standards Committee to develop and test implement a Cost Effectiveness Analysis Procedure (CEAP), which is the first such explicit evaluation conducted during the development of a Regional Reliability Standard, and (iv) the successful recruitment of independent director candidates for Board consideration and selection. The President and CEO noted that each achievement further supported NPCC in "leading the evolution of reliability assurance within North America." He added that within NERC, NPCC was contributing to ERO-wide efficiency by actively participating in the initial stages of the "Find, Fix, Track and Report" compliance enforcement initiative and by assuming a leadership role in "Phase 2" of the initiative which will incorporate a "find-and-fix-in-the-field" component to compliance auditing. Finally, he noted that NPCC's open and interactive culture of compliance survey, which is approximately 80% complete to date, was recently presented to the NERC BOT Compliance Committee as an example of the foundation upon which an efficient risk-based compliance program could be built.

NPCC Committees

Board Committees – The President and CEO presented for Board approval the 2012 roster of committee members for the Corporate Governance and Nominating Committee ("*CGNC"*), the Finance and Audit Committee ("*FAC'*), the Management Development and Compensation Committee ("*MDCC*") and the Pension Committee, with three modifications: (i) Glen McCartney had volunteered to serve on the MDCC for 2012 and had resigned from the CGNC; (ii) André Boulanger had volunteered to serve on the CGNC for 2012; and (iii) David Boguslawski had volunteered to serve on the CGNC for 2012. A motion to approve the following designation of the members of the CGNC, FAC, MDCC and Pension Committee for 2012 was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board.

CORPORATE GOVERNANCE AND NOMINATING COMMITTEE - 2012

Harvey J. Reed	Board Chair – Chair of CGNC
Andrew Barrett	Board Director
André Boulanger	Board Director
David Boguslawski	Board Director
Edward A. Schwerdt	President and CEO
Andrianne S. Payson	Secretary (non-voting)

FINANCE AND AUDIT COMMITTEE - 2012

Christopher Weir, CPA	Treasurer – Chair of FAC
Peter Brandien	Board Director
Bruce B. Campbell	Board Director
Daniel Whyte	Board Director
Jennifer Budd Mattiello	Vice President and COO
Andrianne S. Payson	Secretary (non-voting)

MANAGEMENT DEVELOPMENT AND COMPENSATION COMMITTEE - 2012

Harvey J. Reed	Board Chair – Chair of MDCC
William G. Longhi	Board Director
Peter Brandien	Board Director
Glen McCartney	Board Director
Andrew J. Fawbush	Assistant Secretary (non-voting)

PENSION COMMITTEE - 2012

Edward A. Schwerdt	President and CEO – Chair of Pension Committee
Robert J. DeAngelo	Assistant Treasurer (Northeast Utilities)
Michael Forte	Board Director
Hans Mertens	Board Director
Michael Penstone	Board Director
Jennifer Budd Mattiello	Vice President and COO
Andrew J. Fawbush	Assistant Secretary (non-voting)

Technical Committees – The President then presented for Board approval the list of members of the Regional Standards Committee ("*RSC*"), the Compliance Committee ("*CC*"), the Reliability Coordinating Committee ("*RCC*") and the Public Information Committee ("PIC") for 2012, with one modification to the RCC: the NextEra Energy Resources representative on the RCC has not yet been designated for 2012. A motion to approve the following revised designation of the members of the RSC, CC, RCC, and PIC for 2012 was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board. In response to questions from the Board, the President and CEO explained that the roster for each NPCC committee was subject to final approval by the Board, but that the membership of NPCC's technical task forces is approved by the RCC.

REGIONAL STANDARDS COMMITTEE - 2012

Chairman	Guy V. Zito, Assistant Vice President – Standards, NPCC
Co-Vice Chairman	Gregory A. Campoli, New York Independent System Operator
Co-Vice Chairman	Michael R. Lombardi, Northeast Utilities

Sector 1 – Transmission Owners

David Kiguel, P. Eng, Hydro One Networks Inc.
Christopher L. de Graffenreid, Consolidated Edison Company of New York, Inc.
Michael Schiavone, National Grid
Randy MacDonald, P.Eng, New Brunswick Power Transmission Corporation
Robert J. Pellegrini, The United Illuminating Company
Sylvain Clermont, Hydro-Québec TransÉnergie
Michael R. Lombardi, Northeast Utilities
Ben Wu, Orange and Rockland Utilities, Inc.

ALTERNATES

Ajay Garg, P. Eng, Hydro One Networks Inc.

Sector 2 – Reliability Coordinators

Donald Weaver, New Brunswick System Operator
Gregory A. Campoli, New York Independent System Operator
Kathleen M. Goodman, ISO New England, Inc.
Tina Teng, Independent Electricity System Operator

ALTERNATES

Scott Berry, Independent Electricity System Operator
Esther Kim, Independent Electricity System Operator

Sector 3 – Transmission Dependent Utilities, Distribution Companies, and Load-Serving Entities

Peter Yost, Consolidated Edison Company of New York, Inc.
Saurabh Saksena, National Grid

ALTERNATES

Anthony LaRusso, National Grid

Sector 4 – Generator Owners

Wayne Sipperly, New York Power Authority
Mike Garton, Dominion Resources Services, Inc.
David Ramklawan, P. Eng., Ontario Power Generation Inc.
Chantel Haswell, FPL Group, Inc.

ALTERNATES

Saul Rojas, New York Power Authority

Sector 5 – Marketers, Brokers, and Aggregators

Bruce Metruck, New York Power Authority
Brian Evans-Mongeon, Utility Services LLC

ALTERNATES

Daniella Piper, New York Power Authority

Sector 6 – State and Provincial Regulatory and/or Governmental Authorities

Diane J. Barney, New York State Public Service Commission, Department of Public Service

Sector 7 – Sub-Regional Reliability Councils, Others and Customers

Alan Adamson, Consultant, New York State Reliability Council, LLC

COMPLIANCE COMMITTEE - 2012

Chairman	Stanley E. Kopman, Assistant Vice President – Compliance, NPCC
Vice Chair	Peter Yost, Consolidated Edison Company of New York, Inc.

Sector 1 – Transmission Owners

Ajay Garg, P. Eng, Hydro One Networks Inc.
William Temple, Northeast Utilities
Sylvain Clermont, P. Eng., Hydro-Québec TransÉnergie
Edward F. Dahill, P.E., National Grid
Peter Yost, Consolidated Edison Company of New York, Inc.
Kim Moulton, Vermont Electric Power Company, Inc.
Edward Bedder, Orange and Rockland Utilities, Inc.
Jonathan Appelbaum, The United Illuminating Company
John Robertson, NSTAR Electric

ALTERNATES

Chris de Graffenreid, Consolidated Edison Company of New York, Inc.
Mark Atkins, Vermont Electric Power Company, Inc.
David Burke, Orange and Rockland Utilities, Inc.
Mike Lombardi, Northeast Utilities
David Kiguel, P. Eng.,Hydro One Networks, Inc.
Michael Bilheimer, The United Illuminating Company

Sector 2 – Reliability Coordinators

Calvin Duncan, P. Eng., New Brunswick System Operator
Gregory Campoli, New York Independent System Operator
Richard Burke, ISO New England, Inc.
Joseph Fox, ing., Hydro-Québec TransÉnergie
Esther Kim, Independent Electricity System Operator

ALTERNATES

Scott Berry, Independent Electricity System Operator (Alternate #1)
Tina Teng, Independent Electricity System Operator (Alternate #2)
Matthew Goldberg, ISO New England, Inc.

Sector 3 – Transmission Dependent Utilities, Distribution Companies, and Load-Serving Entities

Vicki M. O'Leary, National Grid
Ben Wu, Orange and Rockland Utilities, Inc.

ALTERNATES

Michael Jones, National Grid

Sector 4 – Generator Owners

Thomas Czerniewski, Entergy Services, Inc.
Chantel Haswell, NextEra Eneryg Resources, LLC
Mike Garton, Dominion Resources Services, Inc.

ALTERNATES

Michael Gildea, Dominion Resource Services
Brian Murphy, NextEra Energy Resources, LLC

Sector 5 – Marketers, Brokers, and Aggregators

Bruce Metruck, New York Power Authority
Brian Evans-Mongeon, Utility Services, Inc.

ALTERNATES

Wayne Sipperly, New York Power Authority

Sector 6 – State/Provincial Regulatory and/or Governmental Authorities

Randy D. Crissman, New York Power Authority

Sector 7 – Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities

To Be Determined

ALTERNATES

Saul Rojas, New York Power Authority

RELIABILITY COORDINATING COMMITTEE - 2012

Chairman	Donald L. Gates, ISO New England, Inc.
Co-Vice Chairman	Michael Schiavone, National Grid
Co-Vice Chairman	Alden Briggs, New Brunswick System Operator

Sector 1 – Transmission Owners

Randy MacDonald, New Brunswick Power Transmission Corporation
Tony O'Hara, New Brunswick Power Transmission Corporation (Alternate)
Brian Conroy, Central Maine Power Company
David Conroy, Central Maine Power Company (Alternate)
Michael Schiavone, National Grid
Robert J. Pellegrini, The United Illuminating Company
Jonathan Appelbaum, The United Illuminating Company
Paul Renaud, Vermont Electric Power Company, Inc.
Hantz A. Présumé, Vermont Electric Power Company, Inc. (Alternate)
Thomas C. Duffy, Central Hudson Gas & Electric Corporation
Michael Forte, Consolidated Edison Company of New York, Inc.
Peter Yost, Consolidated Edison Company of New York, Inc. (Alternate)
David Clarke Long Island Power Authority
Brad Bentley, Northeast Utilities
Steve DeCarlo, New York Power Authority
Michael Parisi, New York Power Authority (Alternate)
Raymond Kinney, New York State Electric & Gas Corp.
Joseph Fleury, New York State Electric & Gas Corp. (Alternate)
John Allen, Rochester Gas and Electric Corporation
Paul Casey, Nova Scotia Power Inc.
David Sanford, Nova Scotia Power Inc. (Alternate)
Paul Tremblay, Hydro One Networks, Inc.
John Sabiston, Hydro One Networks, Inc. (Alternate)

Sector 2 – Reliability Coordinators

Alden Briggs, New Brunswick System Operator
Donald L. Gates, ISO New England, Inc.
Mike Henderson, ISO New England, Inc. (Alternate)
Dana Walters, New York Independent System Operator
Barbara Constantinescu, Independent Electricity System Operator
Len Kula, Independent Electricity System Operator (Alternate)
Pierre Paquet, Hydro-Québec TransÉnergie

Sector 3 – Transmission Dependent Utilities, Distribution Companies, and Load-Serving Entities

Stéphane Dufresne, Hydro-Québec Distribution
Luc Bernier, Hydro-Québec Distribution (Alternate)
Curt Dahl, Long Island Power Authority
Steve Marron, Long Island Power Authority (Alternate)
Marilyn Brown, New York Power Authority
Andrew Stewart, New York Power Authority (Alternate)

Dwayne Basler, Northeast Utilities

Sector 4 – Generator Owners

Michael Garton, Dominion Resources Services, Inc.
Michael Gildea, Dominion Resources Services, Inc. (Alternate)
Jim Watson, Dynegy, Inc.
Dean Ellis, Dynegy Inc. (Alternate)
Thomas Czerniewski, Entergy Nuclear Northeast, Inc.
To Be Determined, NextEra Energy Resources, LLC
David Appelbaum, NextEra Energy Resources, LLC (Alternate)
Yuri Fisman, Long Island Power Authority
Edward Welz, New York Power Authority
Brad Van Auken, New York Power Authority (Alternate)
David Ramklawan, Ontario Power Generation, Inc.
William Smagula, Northeast Utilities
Drew O'Keefe, Northeast Utilities (Alternate)

Sector 5 – Marketers, Brokers, and Aggregators

Glen McCartney, Constellation Energy Commodities Group, Inc.
Louis Guilbault, Hydro-Québec Energy Services (US) Inc.
Scott Leuthauser, Hydro-Québec Energy Services (US) Inc.
Yannick Vennes, Hydro-Québec Energy Marketing, Inc.
Ben Chu, Long Island Power Authority
William Nadeau, New York Power Authority
William Palazzo, New York Power Authority (Alternate)
Bradley Weghorst, PPL Energy Plus, LLC
Mark Heimbach, PPL Energy Plus, LLC (Alternate)
Brian Evans-Mongeon, Utility Services, LLC
John Helme, Utility Services, LLC

Sector 6 – State and Provincial Regulatory and/or Governmental Authorities

TBA, New York State Department of Public Service
Edward Schrom, Jr., New York State Department of Public Service (Alternate)
Bruce Metruck, New York Power Authority
Wayne Sipperly, New York Power Authority

Sector 7 – Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities

Roger Clayton, New York State Reliability Council, LLC
George C. Loehr, New York State Reliability Council, LLC (Alternate)

PUBLIC INFORMATION COMMITTEE - 2012

Chairman	Steve Allen, Salient Point LLC
Members:	
New England:	Ellen Foley, ISO New England, Inc.
New York:	Michael Clendenin, Consolidated Edison Company of New York, Inc. John Cordi, New York Independent System Operator
PJM:	Ray E. Dotter, PJM Interconnection
Maritimes:	Michel Losier, NB Power Holding Corporation

Midwest ISO:	To be determined
Québec:	To be determined
Ontario:	Terry Young, Independent Electricity System Operator
ReliabilityFirst:	Larry Bugh, ReliabilityFirst Corporation
NERC:	Kimberly Mielcarek, NERC
ALTERNATES	Vera B. Geba, Salient Point LLC
	Gary Paslow, New York Independent System Operator

NPCC Committee Reports – The President and CEO informed the Board that the committee reports would be presented during the Annual Members Meeting scheduled for later that morning.

Designation of NPCC Officers

The President and CEO presented for Board approval the proposed designation of NPCC's officers for 2012. A motion to approve the designation of NPCC's officers for 2012 was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board.

NPCC OFFICERS - 2012

Edward A. Schwerdt	President and CEO
Jennifer Budd Mattiello	Vice President and COO
William G. Longhi	Vice Chairman
Bruce B. Campbell	Vice Chairman
Andrianne S. Payson, Esq.	Secretary
Andrew J. Fawbush, Esq.	Assistant Secretary
Christopher Weir, CPA	Treasurer
Robert J. DeAngelo	Assistant Treasurer

Approval of 2012 NPCC Independent Board Chair

The Board Chair left the meeting. Mr. Longhi then presented the draft Independent Consulting Agreement for NPCC's Independent Board Chair. The President and CEO informed the Board of the changes in the draft Independent Consulting Agreement, which reflected (i) a term that commences on January 1, 2012 and ends on December 31, 2013, and (ii) an increase in the retainer and the services included under the retainer for 2012-2013 to make the agreement for the Board Chair more compatible with the contracts for the NPCC independent directors for the same two-year term. One Board member inquired into the performance review process of the Board Chair for 2011. Several Board members provided their individual assessment of the Board Chair's performance during the past year and Ms. Payson provided summary results of the Board self-assessment questionnaire on this specific item. The Board recommended that going forward the CGNC should provide it with the results of the annual Board self-assessment questionnaire on the performance of the Board Chair for that year and a written summary of the Board Chair's performance for the past year, prior to presenting the Board with the draft Independent Consulting Agreement for the Board Chair. Following further discussion, a motion to retain Mr. Reed as Chairman of the NPCC Board of Directors for 2012-2013 and to approve the Independent Consulting Agreement as presented was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board. The Board Chair then returned to the Board meeting.

Organizational Matters

MDCC Recommendations – The President informed the Board that after discussions with the MDCC, he was recommending to the Board a merit salary increase of 3% effective January 1, 2012 for NPCC Staff, which reflects their significant efforts and achievements this past year. He explained that the proposed 3% increase was consistent with the NPCC budget and with merit salary increases that other Regional Entities had approved for their staff. Mr. Longhi added that based on the research conducted and Regional surveys reviewed by the MDCC, the committee believed that a proposed merit package increase of 3% was consistent with merit package increases approved by other organizations in the industry. The Board Chair noted that the MDCC had endorsed the proposed 3% merit increase and presented draft resolutions for Board review and approval. A motion to approve the MDCC's recommendation of a 3% merit salary increase for NPCC Staff in 2012 was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board with one abstention. Following the vote, the Board briefly discussed the publication of NPCC Board minutes on the Members only section of NPCC's website.

The President and CEO and the Vice President and COO then left the meeting. Mr. Fawbush then joined the meeting via teleconference.

The Board Chair distributed draft Board resolutions with the MDCC's recommendation for the President and CEO's salary increase for 2012. He then provided the Board with an update of recent MDCC activities in connection with the annual performance review of the President and CEO. He explained to the Board that the MDCC met previously to discuss the performance of the President and CEO during 2011 and to review comparable salaries paid to other Regional Entity Presidents. He noted that on behalf of the MDCC, he had conducted a "360 review" by which he had interviewed the "direct reports" of the President and CEO, as well as Board members, other Regional Entity Presidents and NERC Staff members regarding the performance of the President and CEO during 2011. The Board Chair provided a summary of the feedback he received regarding the President and CEO's performance in 2011 and informed the Board that an independent compensation consultant would be retained in 2012 to conduct a compensation review for the President and CEO position as well as the positions held by other senior staff. The Board noted that the MDCC would oversee the work performed by the compensation consultant and requested that the MDCC provide regular updates to the Board of the work performed by the compensation consultant. Several Board members expressed their views regarding the appropriate level of compensation that should be paid to the NPCC President and CEO for 2012, taking into account the salaries paid to other Regional Entity Presidents in a competitive market, NPCC's status as a "quasi-public" not-for-profit corporation in the State of New York, and that the "economy is shrinking" as reflected by the austerity measures implemented by many states. Following discussion, a motion to approve the MDCC's recommendation of an increase in the base salary of the President and CEO was duly made, seconded and approved by the Directors in each active Sector of the Board with one abstention.

Mr. Fawbush left the meeting. The President and CEO and the Vice President and COO then returned to the meeting.

Topics for 2012 Board Strategy Session – The Board Chair informed the Board that he had prepared a list of topics for the upcoming 2012 Board Strategy Session, which included the following: (i) the industry perception of NPCC compared to other Regions and NPCC's steps to reach the "next level" as a Regional Entity; (ii) Board policy positions, particularly if they conflict with positions taken by NPCC members; (iii) the format for written reports submitted by Board committees; (iv) balancing the President and CEO function and the role of the Board; and (v) Board policy or strategic issues for input into the "NERC One Enterprise Planning Process." Board members spent a fair amount of time discussing the perception of NPCC among the other Regional Entities, the relationship between regulators and the industry, and the influence of politics on the relationship between the two groups. The Board agreed to resume thediscussion

of these items during the 2012 Board Strategy Session. The President and CEO asked Board members to submit additional topics for the 2012 Board Strategy Session.

Administrative Matters

Board Self-Assessment – The Board Chair reminded Board members to submit their responses to the NPCC Board 2011 self-assessment matrix. He noted that the results of the Board self-assessment would be discussed in detail during the Board's Strategy Session on January 31, 2012.

Other Matters

FERC Approval of NPCC as WECC Compliance Enforcement Authority – The Board noted the FERC letter dated November 15, 2011 approving NERC's petition for NPCC to serve as the Compliance Enforcement Authority for WECC-registered functions in the United States portion of the WECC Region. The FERC letter was previously circulated in the Board agenda package prior to the Board meeting.

Approval of NPCC Regional Standard PRC-006-NPCC-01 – Mr. Guy Zito, NPCC's Assistant Vice President – Standards, joined the meeting to present the RSC's second proposed Regional Reliability Standard, *Automatic Underfrequency Load Shedding*, for Board consideration and approval. Mr. Zito explained that the RSC started working on the proposed standard in July 2009, and had just completed its third draft, which was posted for comment on the NPCC website on May 6, 2011. He noted that the process to develop the proposed standard included two meetings with NERC, two NERC quality reviews, a presentation to the industry at a Compliance workshop, the development of a Cost Effective Analysis Procedure (CEAP) at the Board's request, and application of the CEAP to the proposed standard to assess its cost impact. He further noted that CEAP was also presented at the North American Generator Forum in Atlanta on October 11, 2011. Mr. Zito informed the Board that there was a completed ballot on November 18, 2011 with an 83% affirmative vote approving the draft regional standard. He explained that Hydro-Québec recently identified a minor correction to the proposed standard, and had requested Board approval of the correction as a non-substantive change to the proposed standard. The Board noted that the error appeared on page 29 of the proposed standard in UFLS Table 4: Québec Interconnection, and that the asterisk in Table 4 should read "Load must be fixed at all times *when above 60% of the peak load*." In response to questions from the Board, Mr. Zito noted the following: (i) he believed that the 2-1/2 years it took to develop the proposed standard would not be the typical timeframe to develop a Regional Standard; and (ii) the CEAP for the proposed standard had an estimated cost of $8 million for the UFLS program change and implementation, which reflects only the capital costs) submitted by the Members who responded to the survey. Mr. Zito explained the $8 million estimate did not reflect the total potential costs of implementation within the NPCC Region by all Members, or include any ongoing maintenance costs. One Board member noted that there was no calculation of the "benefits" that would be realized by the proposed standard and questioned whether the RSC attempted to quantify benefits as part of a cost-benefits analysis for the proposed standard. The Board was informed that, in this instance, the CEAP was applied to a standard already under development and that the reliability need had been identified as a 2003 Blackout recommendation. The Board questioned the feasibility of quantifying the benefits of the proposed standard, but noted that NPCC's work in the reliability area since the 1965 Black-out could attest to the "benefits" realized to date. Following further Board discussion, Mr. Zito agreed to complete a "benefits" assessment as part of CEAP going forward. The Board agreed to continue the cost-benefits analysis discussion during the 2012 Board Strategy Session. A motion to approve the draft *Automatic Underfrequency Load Shedding* Regional Standard PRC-006-NPCC-01 was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Adjournment

There being no further business, the Board Chair adjourned the meeting of the NPCC Board of Directors at 10:20 a.m.

Approved by Board action on _____, 2012.

Submitted by,

_____
Andrianne S. Payson
NPCC Secretary

EXHIBIT C
LIST OF ATTENDEES
November 30, 2011

Present:	Harvey J. Reed, Chairman Edward A. Schwerdt, President and CEO Jennifer Budd Mattiello, Vice President and COO Andrianne S. Payson, Esq., Secretary Andrew J. Fawbush, Esq., Assistant Secretary
	And the following members of the Board of Directors:
Sector 1 (TOs)	William G. Longhi, Orange and Rockland Utilities, Inc. André Boulanger, Hydro-Québec TransÉnergie
Sector 2 (RCs)	Peter Brandien, ISO New England, Inc. Bruce B. Campbell, Independent Electricity System Operator Rick Gonzales, New York Independent System Operator, Inc. (via teleconference)
Sector 3 (TDUs, DCs, LSEs)	David H. Boguslawski, Northeast Utilities Michael Penstone, Hydro One
Sector 4 (GOs)	Andrew Barrett, Ontario Power Generation, Inc.
Sector 5 (Marketers, Brokers and Aggregators)	Glen McCartney, Constellation Energy Commodities Group, Inc. Matthew J. Picardi, Shell Energy NA (by proxy to the President) Daniel Whyte, Brookfield Power Generation
Sector 6 (Customers)	–
Sector 7 (Regulatory)	Hans Mertens, Vermont Department of Public Service Tammy Mitchell, NYS Department of Public Service (via teleconference)
Sector 8 (Others)	Michael Forte, New York State Reliability Council, LLC
Guests	Guy Zito, NPCC Assistant Vice President, Reliability Standards

Northeast Power Coordinating Council, Inc. Board of Directors Meeting
REVISED Draft Minutes for Approval

November 30, 2011 | 7:35 a.m.
Toronto Marriott Bloor Yorkville, Toronto, Ontario

The Chairman called to order a duly noticed meeting of the Board of Directors ("*Board*") of Northeast Power Coordinating Council, Inc. ("*NPCC*") held on November 30, 2011, at 7:35 a.m. A quorum was declared present during the meeting by the President and CEO, Edward Schwerdt. Andrianne Payson acted as Recording Secretary. The meeting announcement, agenda and list of attendees are attached as **Exhibits A, B, and C**, respectively.

NPCC Antitrust Compliance Guidelines

The Chairman recommended that a reading of the *NPCC Antitrust Compliance Guidelines* that were distributed via email with the Board agenda package and reviewed by Directors upon commencement of the meeting be waived. A motion to waive the reading of the *NPCC Antitrust Compliance Guidelines* was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Minutes

The President and CEO presented for approval a draft of the minutes of the Board teleconference held on October 26, 2011. A motion to approve the minutes of the NPCC Board of Directors teleconference held on October 26, 2011 was duly made, seconded and approved by the majority of Directors in each active Sector of the Board with one abstention.

Future Meetings

The President and CEO presented the schedule of Board meetings for calendar year 2012. He noted that the Board's Strategy Session would be held the afternoon of Monday, January 31, 2012 and that the first Board meeting for the year would follow the next morning on Tuesday, February 1, 2012.

President's Report

The President and CEO presented his report to the Board, which is summarized below.

Bulk Electric System – The President and CEO informed the Board that two NERC recirculation ballots, one for the Bulk Electric System ("*BES*") definition and a second for the criteria to request an exception, closed on November 21, 2011 and were approved by stakeholders. The first ballot approving the BES definition received an 81.32% affirmative vote and the second ballot approving the exception criteria received an 81.48% affirmative vote. The President and CEO noted that from an industry-wide perspective, virtually all of the Canadian "ballot" members either abstained from the vote or voted against the BES definition. He explained that the stakeholder approved BES definition, its related implementation plan and supporting application form for exception requests will be presented to the NERC Board of Trustees ("*BOT*") for adoption and subsequently filed with the regulatory authorities. He noted that the regulatory deadline in FERC Order No. 743 *Revision of the Electric Reliability Organization Definition of Bulk Electric System* and related FERC Order No. 743-A requires that the revised BES definition and the process for handling exceptions be filed by January 25, 2012. He explained that NPCC recently met with FERC senior staff to discuss any concerns that FERC may have regarding implementation of the BES definition within NPCC's geographic footprint in the United States. He further explained that NPCC's informal

meeting with FERC senior staff provided an opportunity for frank discussion and allowed for clarification of the BES exceptions regarding (i) the content of the January 25, 2012 compliance filing, (ii) the criteria for inclusions and exclusions, (iii) the procedure for identification of the new BES facilities, (iv) the process for requesting and granting exceptions, and (v) the issues that will be considered by the industry as part of Phase 2 of the BES project. The President and CEO informed the Board that NPCC faced a significant amount of work in 2012 regarding implementation of the BES definition within NPCC's Canadian Provinces.

NPCC Activities During 2011 – The President and CEO reported that there were several achievements during calendar year 2011, including (i) FERC approval of NPCC's Amended & Restated Bylaws which reflected specific enhancements in NPCC's corporate governance structure, (ii) FERC approval of the expansion of the *Regional Delegation Agreement* to incorporate NPCC's role as the Compliance Enforcement Authority for WECC's Reliability Coordinator function, (iii) the Board's direction to NPCC's Regional Standards Committee to develop and test implement a Cost Effectiveness Analysis Procedure (CEAP), which is the first such explicit evaluation conducted during the development of a Regional Reliability Standard, and (iv) the successful recruitment of independent director candidates for Board consideration and selection. The President and CEO noted that each achievement further supported NPCC in "leading the evolution of reliability assurance within North America." He added that within NERC, NPCC was contributing to ERO-wide efficiency by actively participating in the initial stages of the "Find, Fix, Track and Report" compliance enforcement initiative and by assuming a leadership role in "Phase 2" of the initiative which will incorporate a "find-and-fix-in-the-field" component to compliance auditing. Finally, he noted that NPCC's open and interactive culture of compliance survey, which is approximately 80% complete to date, was recently presented to the NERC BOT Compliance Committee as an example of the foundation upon which an efficient risk-based compliance program could be built.

NPCC Committees

Board Committees – The President and CEO presented for Board approval the 2012 roster of committee members for the Corporate Governance and Nominating Committee ("*CGNC"*), the Finance and Audit Committee ("*FAC'*), the Management Development and Compensation Committee ("*MDCC*") and the Pension Committee, with three modifications: (i) Glen McCartney had volunteered to serve on the MDCC for 2012 and had resigned from the CGNC; (ii) André Boulanger had volunteered to serve on the CGNC for 2012; and (iii) David Boguslawski had volunteered to serve on the CGNC for 2012. A motion to approve the following designation of the members of the CGNC, FAC, MDCC and Pension Committee for 2012 was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board.

CORPORATE GOVERNANCE AND NOMINATING COMMITTEE - 2012

Harvey J. Reed	Board Chair – Chair of CGNC
Andrew Barrett	Board Director
André Boulanger	Board Director
David Boguslawski	Board Director
Edward A. Schwerdt	President and CEO
Andrianne S. Payson	Secretary (non-voting)

FINANCE AND AUDIT COMMITTEE - 2012

Christopher Weir, CPA	Treasurer – Chair of FAC
Peter Brandien	Board Director
Bruce B. Campbell	Board Director
Daniel Whyte	Board Director
Jennifer Budd Mattiello	Vice President and COO
Andrianne S. Payson	Secretary (non-voting)

MANAGEMENT DEVELOPMENT AND COMPENSATION COMMITTEE - 2012

Harvey J. Reed	Board Chair – Chair of MDCC
William G. Longhi	Board Director
Peter Brandien	Board Director
Glen McCartney	Board Director
Andrew J. Fawbush	Assistant Secretary (non-voting)

PENSION COMMITTEE - 2012

Edward A. Schwerdt	President and CEO – Chair of Pension Committee
Robert J. DeAngelo	Assistant Treasurer (Northeast Utilities)
Michael Forte	Board Director
Hans Mertens	Board Director
Michael Penstone	Board Director
Jennifer Budd Mattiello	Vice President and COO
Andrew J. Fawbush	Assistant Secretary (non-voting)

Technical Committees – The President then presented for Board approval the list of members of the Regional Standards Committee ("*RSC*"), the Compliance Committee ("*CC*"), the Reliability Coordinating Committee ("*RCC*") and the Public Information Committee ("PIC") for 2012, with one modification to the RCC: the NextEra Energy Resources representative on the RCC has not yet been designated for 2012. A motion to approve the following revised designation of the members of the RSC, CC, RCC, and PIC for 2012 was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board. In response to questions from the Board, the President and CEO explained that the roster for each NPCC committee was subject to final approval by the Board, but that the membership of NPCC's technical task forces is approved by the RCC.

REGIONAL STANDARDS COMMITTEE - 2012

Chairman	Guy V. Zito, Assistant Vice President – Standards, NPCC
Co-Vice Chairman	Gregory A. Campoli, New York Independent System Operator
Co-Vice Chairman	Michael R. Lombardi, Northeast Utilities

Sector 1 – Transmission Owners

David Kiguel, P. Eng, Hydro One Networks Inc.
Christopher L. de Graffenreid, Consolidated Edison Company of New York, Inc.
Michael Schiavone, National Grid
Randy MacDonald, P.Eng, New Brunswick Power Transmission Corporation
Robert J. Pellegrini, The United Illuminating Company
Sylvain Clermont, Hydro-Québec TransÉnergie
Michael R. Lombardi, Northeast Utilities
Ben Wu, Orange and Rockland Utilities, Inc.

ALTERNATES

Ajay Garg, P. Eng, Hydro One Networks Inc.

Sector 2 – Reliability Coordinators

Donald Weaver, New Brunswick System Operator
Gregory A. Campoli, New York Independent System Operator
Kathleen M. Goodman, ISO New England, Inc.
Tina Teng, Independent Electricity System Operator

ALTERNATES

Scott Berry, Independent Electricity System Operator
Esther Kim, Independent Electricity System Operator

Sector 3 – Transmission Dependent Utilities, Distribution Companies, and Load-Serving Entities

Peter Yost, Consolidated Edison Company of New York, Inc.
Saurabh Saksena, National Grid

ALTERNATES

Anthony LaRusso, National Grid

Sector 4 – Generator Owners

Wayne Sipperly, New York Power Authority
Mike Garton, Dominion Resources Services, Inc.
David Ramklawan, P. Eng., Ontario Power Generation Inc.
Chantel Haswell, FPL Group, Inc.

ALTERNATES

Saul Rojas, New York Power Authority

Sector 5 – Marketers, Brokers, and Aggregators

Bruce Metruck, New York Power Authority
Brian Evans-Mongeon, Utility Services LLC

ALTERNATES

Daniella Piper, New York Power Authority

Sector 6 – State and Provincial Regulatory and/or Governmental Authorities

Diane J. Barney, New York State Public Service Commission, Department of Public Service

Sector 7 – Sub-Regional Reliability Councils, Others and Customers

Alan Adamson, Consultant, New York State Reliability Council, LLC

COMPLIANCE COMMITTEE - 2012

Chairman	Stanley E. Kopman, Assistant Vice President – Compliance, NPCC
Vice Chair	Peter Yost, Consolidated Edison Company of New York, Inc.

Sector 1 – Transmission Owners

Ajay Garg, P. Eng, Hydro One Networks Inc.
William Temple, Northeast Utilities
Sylvain Clermont, P. Eng., Hydro-Québec TransÉnergie
Edward F. Dahill, P.E., National Grid
Peter Yost, Consolidated Edison Company of New York, Inc.
Kim Moulton, Vermont Electric Power Company, Inc.
Edward Bedder, Orange and Rockland Utilities, Inc.
Jonathan Appelbaum, The United Illuminating Company
John Robertson, NSTAR Electric

ALTERNATES

Chris de Graffenreid, Consolidated Edison Company of New York, Inc.
Mark Atkins, Vermont Electric Power Company, Inc.
David Burke, Orange and Rockland Utilities, Inc.
Mike Lombardi, Northeast Utilities
David Kiguel, P. Eng.,Hydro One Networks, Inc.
Michael Bilheimer, The United Illuminating Company

Sector 2 – Reliability Coordinators

Calvin Duncan, P. Eng., New Brunswick System Operator
Gregory Campoli, New York Independent System Operator
Richard Burke, ISO New England, Inc.
Joseph Fox, ing., Hydro-Québec TransÉnergie
Esther Kim, Independent Electricity System Operator

ALTERNATES

Scott Berry, Independent Electricity System Operator (Alternate #1)
Tina Teng, Independent Electricity System Operator (Alternate #2)
Matthew Goldberg, ISO New England, Inc.

Sector 3 – Transmission Dependent Utilities, Distribution Companies, and Load-Serving Entities

Vicki M. O'Leary, National Grid
Ben Wu, Orange and Rockland Utilities, Inc.

ALTERNATES

Michael Jones, National Grid

Sector 4 – Generator Owners

Thomas Czerniewski, Entergy Services, Inc.
Chantel Haswell, NextEra Eneryg Resources, LLC
Mike Garton, Dominion Resources Services, Inc.

ALTERNATES

Michael Gildea, Dominion Resource Services
Brian Murphy, NextEra Energy Resources, LLC

Sector 5 – Marketers, Brokers, and Aggregators

Bruce Metruck, New York Power Authority
Brian Evans-Mongeon, Utility Services, Inc.

ALTERNATES

Wayne Sipperly, New York Power Authority

Sector 6 – State/Provincial Regulatory and/or Governmental Authorities

Randy D. Crissman, New York Power Authority

Sector 7 – Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities

To Be Determined

ALTERNATES

Saul Rojas, New York Power Authority

RELIABILITY COORDINATING COMMITTEE - 2012

Chairman	Donald L. Gates, ISO New England, Inc.
Co-Vice Chairman	Michael Schiavone, National Grid
Co-Vice Chairman	Alden Briggs, New Brunswick System Operator

Sector 1 – Transmission Owners

Randy MacDonald, New Brunswick Power Transmission Corporation
Tony O'Hara, New Brunswick Power Transmission Corporation (Alternate)
Brian Conroy, Central Maine Power Company
David Conroy, Central Maine Power Company (Alternate)
Michael Schiavone, National Grid
Robert J. Pellegrini, The United Illuminating Company
Jonathan Appelbaum, The United Illuminating Company
Paul Renaud, Vermont Electric Power Company, Inc.
Hantz A. Présumé, Vermont Electric Power Company, Inc. (Alternate)
Thomas C. Duffy, Central Hudson Gas & Electric Corporation
Michael Forte, Consolidated Edison Company of New York, Inc.
Peter Yost, Consolidated Edison Company of New York, Inc. (Alternate)
David Clarke Long Island Power Authority
Brad Bentley, Northeast Utilities
Steve DeCarlo, New York Power Authority
Michael Parisi, New York Power Authority (Alternate)
Raymond Kinney, New York State Electric & Gas Corp.
Joseph Fleury, New York State Electric & Gas Corp. (Alternate)
John Allen, Rochester Gas and Electric Corporation
Paul Casey, Nova Scotia Power Inc.
David Sanford, Nova Scotia Power Inc. (Alternate)
Paul Tremblay, Hydro One Networks, Inc.
John Sabiston, Hydro One Networks, Inc. (Alternate)

Sector 2 – Reliability Coordinators

Alden Briggs, New Brunswick System Operator
Donald L. Gates, ISO New England, Inc.
Mike Henderson, ISO New England, Inc. (Alternate)
Dana Walters, New York Independent System Operator
Barbara Constantinescu, Independent Electricity System Operator
Len Kula, Independent Electricity System Operator (Alternate)
Pierre Paquet, Hydro-Québec TransÉnergie

Sector 3 – Transmission Dependent Utilities, Distribution Companies, and Load-Serving Entities

Stéphane Dufresne, Hydro-Québec Distribution
Luc Bernier, Hydro-Québec Distribution (Alternate)
Curt Dahl, Long Island Power Authority
Steve Marron, Long Island Power Authority (Alternate)
Marilyn Brown, New York Power Authority
Andrew Stewart, New York Power Authority (Alternate)

Dwayne Basler, Northeast Utilities

Sector 4 – Generator Owners

Michael Garton, Dominion Resources Services, Inc.
Michael Gildea, Dominion Resources Services, Inc. (Alternate)
Jim Watson, Dynegy, Inc.
Dean Ellis, Dynegy Inc. (Alternate)
Thomas Czerniewski, Entergy Nuclear Northeast, Inc.
To Be Determined, NextEra Energy Resources, LLC
David Appelbaum, NextEra Energy Resources, LLC (Alternate)
Yuri Fisman, Long Island Power Authority
Edward Welz, New York Power Authority
Brad Van Auken, New York Power Authority (Alternate)
David Ramklawan, Ontario Power Generation, Inc.
William Smagula, Northeast Utilities
Drew O'Keefe, Northeast Utilities (Alternate)

Sector 5 – Marketers, Brokers, and Aggregators

Glen McCartney, Constellation Energy Commodities Group, Inc.
Louis Guilbault, Hydro-Québec Energy Services (US) Inc.
Scott Leuthauser, Hydro-Québec Energy Services (US) Inc.
Yannick Vennes, Hydro-Québec Energy Marketing, Inc.
Ben Chu, Long Island Power Authority
William Nadeau, New York Power Authority
William Palazzo, New York Power Authority (Alternate)
Bradley Weghorst, PPL Energy Plus, LLC
Mark Heimbach, PPL Energy Plus, LLC (Alternate)
Brian Evans-Mongeon, Utility Services, LLC
John Helme, Utility Services, LLC

Sector 6 – State and Provincial Regulatory and/or Governmental Authorities

TBA, New York State Department of Public Service
Edward Schrom, Jr., New York State Department of Public Service (Alternate)
Bruce Metruck, New York Power Authority
Wayne Sipperly, New York Power Authority

Sector 7 – Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities

Roger Clayton, New York State Reliability Council, LLC
George C. Loehr, New York State Reliability Council, LLC (Alternate)

PUBLIC INFORMATION COMMITTEE - 2012

Chairman	Steve Allen, Salient Point LLC
Members:	
New England:	Ellen Foley, ISO New England, Inc.
New York:	Michael Clendenin, Consolidated Edison Company of New York, Inc. John Cordi, New York Independent System Operator
PJM:	Ray E. Dotter, PJM Interconnection
Maritimes:	Michel Losier, NB Power Holding Corporation

Midwest ISO:	To be determined
Québec:	To be determined
Ontario:	Terry Young, Independent Electricity System Operator
ReliabilityFirst:	Larry Bugh, ReliabilityFirst Corporation
NERC:	Kimberly Mielcarek, NERC
ALTERNATES	Vera B. Geba, Salient Point LLC
	Gary Paslow, New York Independent System Operator

NPCC Committee Reports – The President and CEO informed the Board that the committee reports would be presented during the Annual Members Meeting scheduled for later that morning.

Designation of NPCC Officers

The President and CEO presented for Board approval the proposed designation of NPCC's officers for 2012. A motion to approve the designation of NPCC's officers for 2012 was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board.

NPCC OFFICERS - 2012

Edward A. Schwerdt	President and CEO
Jennifer Budd Mattiello	Vice President and COO
William G. Longhi	Vice Chairman
Bruce B. Campbell	Vice Chairman
Andrianne S. Payson, Esq.	Secretary
Andrew J. Fawbush, Esq.	Assistant Secretary
Christopher Weir, CPA	Treasurer
Robert J. DeAngelo	Assistant Treasurer

Approval of 2012 NPCC Independent Board Chair

The Board Chair left the meeting. Mr. Longhi then presented the draft Independent Consulting Agreement for NPCC's Independent Board Chair. The President and CEO informed the Board of the changes in the draft Independent Consulting Agreement, which reflected (i) a term that commences on January 1, 2012 and ends on December 31, 2013, and (ii) an increase in the retainer and the services included under the retainer for 2012-2013 to make the agreement for the Board Chair more compatible with the contracts for the NPCC independent directors for the same two-year term. One Board member inquired into the performance review process of the Board Chair for 2011. Several Board members provided their individual assessment of the Board Chair's performance during the past year and Ms. Payson provided summary results of the Board self-assessment questionnaire on this specific item. The Board recommended that going forward the CGNC should provide it with the results of the annual Board self-assessment questionnaire on the performance of the Board Chair for that year and a written summary of the Board Chair's performance for the past year, prior to presenting the Board with the draft Independent Consulting Agreement for the Board Chair. The Board additionally recommended that the CGNC conduct an annual assessment of the performance of the Independent Directors. Following further discussion, a motion to retain Mr. Reed as Chairman of the NPCC Board of Directors for 2012-2013 and to approve the Independent Consulting Agreement as presented was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board. The Board Chair then returned to the Board meeting.

Organizational Matters

MDCC Recommendations – The President informed the Board that after discussions with the MDCC, he was recommending to the Board a merit salary increase of 3% effective January 1, 2012 for NPCC Staff, which reflects their significant efforts and achievements this past year. He explained that the proposed 3% increase was consistent with the NPCC budget and with merit salary increases that other Regional Entities had approved for their staff. Mr. Longhi added that based on the research conducted and Regional surveys reviewed by the MDCC, the committee believed that a proposed merit package increase of 3% was consistent with merit package increases approved by other organizations in the industry. The Board Chair noted that the MDCC had endorsed the proposed 3% merit increase and presented draft resolutions for Board review and approval. A motion to approve the MDCC's recommendation of a 3% merit salary increase for NPCC Staff in 2012 was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board with one abstention. Following the vote, the Board briefly discussed the publication of NPCC Board minutes on the Members only section of NPCC's website.

The President and CEO and the Vice President and COO then left the meeting. Mr. Fawbush then joined the meeting via teleconference.

The Board Chair distributed draft Board resolutions with the MDCC's recommendation for the President and CEO's salary increase for 2012. He then provided the Board with an update of recent MDCC activities in connection with the annual performance review of the President and CEO. He explained to the Board that the MDCC met previously to discuss the performance of the President and CEO during 2011 and to review comparable salaries paid to other Regional Entity Presidents. He noted that on behalf of the MDCC, he had conducted a "360 review" by which he had interviewed the "direct reports" of the President and CEO, as well as Board members, other Regional Entity Presidents and NERC Staff members regarding the performance of the President and CEO during 2011. The Board Chair provided a summary of the feedback he received regarding the President and CEO's performance in 2011 and informed the Board that an independent compensation consultant would be retained in 2012 to conduct a compensation review for the President and CEO position as well as the positions held by other senior staff. The Board noted that the MDCC would oversee the work performed by the compensation consultant and requested that the MDCC provide regular updates to the Board of the work performed by the compensation consultant. Several Board members expressed their views regarding the appropriate level of compensation that should be paid to the NPCC President and CEO for 2012, taking into account the salaries paid to other Regional Entity Presidents in a competitive market, NPCC's status as a "quasi-public" not-for-profit corporation in the State of New York, and that the "economy is shrinking" as reflected by the austerity measures implemented by many states. Following discussion, a motion to approve the MDCC's recommendation of an increase in the base salary of the President and CEO was duly made, seconded and approved by the Directors in each active Sector of the Board with one abstention.

Mr. Fawbush left the meeting. The President and CEO and the Vice President and COO then returned to the meeting.

Topics for 2012 Board Strategy Session – The Board Chair informed the Board that he had prepared a list of topics for the upcoming 2012 Board Strategy Session, which included the following: (i) the industry perception of NPCC compared to other Regions and NPCC's steps to reach the "next level" as a Regional Entity; (ii) Board policy positions, particularly if they conflict with positions taken by NPCC members; (iii) the format for written reports submitted by Board committees; (iv) balancing the President and CEO function and the role of the Board; and (v) Board policy or strategic issues for input into the "NERC One Enterprise Planning Process." Board members spent a fair amount of time discussing the perception of NPCC among the other Regional Entities, the relationship between regulators and the industry, and the

influence of politics on the relationship between the two groups. The Board agreed to resume thediscussion of these items during the 2012 Board Strategy Session. The President and CEO asked Board members to submit additional topics for the 2012 Board Strategy Session.

Administrative Matters

Board Self-Assessment – The Board Chair reminded Board members to submit their responses to the NPCC Board 2011 self-assessment matrix. He noted that the results of the Board self-assessment would be discussed in detail during the Board's Strategy Session on January 31, 2012.

Other Matters

FERC Approval of NPCC as WECC Compliance Enforcement Authority – The Board noted the FERC letter dated November 15, 2011 approving NERC's petition for NPCC to serve as the Compliance Enforcement Authority for WECC-registered functions in the United States portion of the WECC Region. The FERC letter was previously circulated in the Board agenda package prior to the Board meeting.

Approval of NPCC Regional Standard PRC-006-NPCC-01 – Mr. Guy Zito, NPCC's Assistant Vice President – Standards, joined the meeting to present the RSC's second proposed Regional Reliability Standard, *Automatic Underfrequency Load Shedding*, for Board consideration and approval. Mr. Zito explained that the RSC started working on the proposed standard in July 2009, and had just completed its third draft, which was posted for comment on the NPCC website on May 6, 2011. He noted that the process to develop the proposed standard included two meetings with NERC, two NERC quality reviews, a presentation to the industry at a Compliance workshop, the development of a Cost Effective Analysis Procedure (CEAP) at the Board's request, and application of the CEAP to the proposed standard to assess its cost impact. He further noted that CEAP was also presented at the North American Generator Forum in Atlanta on October 11, 2011. Mr. Zito informed the Board that there was a completed ballot on November 18, 2011 with an 83% affirmative vote approving the draft regional standard. He explained that Hydro-Québec recently identified a minor correction to the proposed standard, and had requested Board approval of the correction as a non-substantive change to the proposed standard. The Board noted that the error appeared on page 29 of the proposed standard in UFLS Table 4: Québec Interconnection, and that the asterisk in Table 4 should read "Load must be fixed at all times *when above 60% of the peak load*." In response to questions from the Board, Mr. Zito noted the following: (i) he believed that the 2-1/2 years it took to develop the proposed standard would not be the typical timeframe to develop a Regional Standard; and (ii) the CEAP for the proposed standard had an estimated cost of $8 million for the UFLS program change and implementation, which reflects only the capital costs) submitted by the Members who responded to the survey. Mr. Zito explained the $8 million estimate did not reflect the total potential costs of implementation within the NPCC Region by all Members, or include any ongoing maintenance costs. One Board member noted that there was no calculation of the "benefits" that would be realized by the proposed standard and questioned whether the RSC attempted to quantify benefits as part of a cost-benefits analysis for the proposed standard. The Board was informed that, in this instance, the CEAP was applied to a standard already under development and that the reliability need had been identified as a 2003 Blackout recommendation. The Board questioned the feasibility of quantifying the benefits of the proposed standard, but noted that NPCC's work in the reliability area since the 1965 Black-out could attest to the "benefits" realized to date. Following further Board discussion, Mr. Zito agreed to complete a "benefits" assessment as part of CEAP going forward. The Board agreed to continue the cost-benefits analysis discussion during the 2012 Board Strategy Session. A motion to approve the draft *Automatic Underfrequency Load Shedding* Regional Standard PRC-006-NPCC-01 was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Adjournment

There being no further business, the Board Chair adjourned the meeting of the NPCC Board of Directors at 10:20 a.m.

Approved by Board action on _____, 2012.

Submitted by,

_____
Andrianne S. Payson
NPCC Secretary

EXHIBIT C
LIST OF ATTENDEES
November 30, 2011

Present:	Harvey J. Reed, Chairman Edward A. Schwerdt, President and CEO Jennifer Budd Mattiello, Vice President and COO Andrianne S. Payson, Esq., Secretary Andrew J. Fawbush, Esq., Assistant Secretary
	And the following members of the Board of Directors:
Sector 1 (TOs)	William G. Longhi, Orange and Rockland Utilities, Inc. André Boulanger, Hydro-Québec TransÉnergie
Sector 2 (RCs)	Peter Brandien, ISO New England, Inc. Bruce B. Campbell, Independent Electricity System Operator Rick Gonzales, New York Independent System Operator, Inc. (via teleconference)
Sector 3 (TDUs, DCs, LSEs)	David H. Boguslawski, Northeast Utilities Michael Penstone, Hydro One
Sector 4 (GOs)	Andrew Barrett, Ontario Power Generation, Inc.
Sector 5 (Marketers, Brokers and Aggregators)	Glen McCartney, Constellation Energy Commodities Group, Inc. Matthew J. Picardi, Shell Energy NA (by proxy to the President) Daniel Whyte, Brookfield Power Generation
Sector 6 (Customers)	–
Sector 7 (Regulatory)	Hans Mertens, Vermont Department of Public Service Tammy Mitchell, NYS Department of Public Service (via teleconference)
Sector 8 (Others)	Michael Forte, New York State Reliability Council, LLC
Guests	Guy Zito, NPCC Assistant Vice President, Reliability Standards

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

COMMITTEE MEMBERSHIP CHANGES

Reliability Coordinating Committee (RCC)

Sector (3) – Transmission Dependent Utilities ("TDUs"), Distribution Companies and Load, -Serving Utilities ("LSE")

Ms. Anie Philip as Long Island Power Authority alternate, replacing Mr. Steve Marron.

Regional Standards Committee (RSC)

Sector (5), Marketers, Brokers and Aggregators

Mr. Brian Robinson as Utility Services, Inc. member, replacing Mr. Brian Evans-Mongeon.

Mr. Brian Evans-Mongeon as Utility Services, Inc. alternate.

Compliance Committee (CC)

Sector (5), Marketers, Brokers and Aggregators

Ms. Jill Loewer as Utility Services, Inc. member, replacing Brian Evans-Mongeon.

Mr. Brian Evans-Mongeon as Utility Services, Inc. alternate.

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Scope of Work
for the
Regional Standards Committee (RSC)

The NPCC Regional Standards Committee (RSC), a committee of the NPCC Board of Directors (BOD), is charged with:

1. managing the NPCC Regional Standards Development Process.
2. managing the NPCC Directory and Criteria Development Process.
3. providing consolidated NPCC Regional review and comment to the existing and proposed NERC Standards and Variances as well as participating in the NERC Reliability Standards Development Process.
4. reviewing the FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) related to reliability Standards, providing a forum for developing consensus viewpoints, and submitting comments to FERC, as necessary.
5. reviewing NERC Compliance Application Notices (CANs) working in coordination with the NPCC Compliance Committee (CC) and submitting comments to NERC, as necessary.
6. providing consolidated NPCC Regional review and comment to the existing and proposed NERC Standards Development Process Manual, and to the NERC Rules of Procedure as they relate to Standards Development.
7. determining the need for and coordinating the development and application for interpretations.
8. providing a forum for sharing viewpoints and opinions with the goal of achieving consensus.
9. conducting the NPCC Cost Effective Analysis Procedure "CEAP" for developing regional standards and produce the associated reports

The RSC or RSC Executive Committee will solicit input from NPCC groups and for all submissions of standards related comments on behalf of NPCC in accordance with the RSC Triage process. The RSC will be the only group submitting comments to FERC, NERC, or any other industry entities on behalf of the NPCC Region.

The RSC is an open and balanced stakeholder committee inclusive of all industry stakeholder interests that provide for or are materially impacted by the reliability of the bulk power system.

The RSC meetings will be open to all stakeholders who want to participate and 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 NPCC Standards Staff which will administer the NPCC Regional Standards Process(es) and coordinate the review and submission of comments.

The RSC will be chaired by an NPCC member of Staff who will be assisted by the NPCC Regional Standards Process Manager (also a member of NPCC Staff) along with co-vice chairs elected by the RSC from the existing members of the Committee at the time the vote is taken. 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 in accordance with the NPCC Amended and Restated Bylaws.

Members of the RSC will be elected by the NPCC Board. Each of the NPCC Sectors, as defined in the NPCC Amended and Restated Bylaws, will be represented on the RSC.

Subcommittees and ad hoc Working Groups will be formed upon request of the RSC, by NPCC Standards program area Staff and all associated scopes or charters developed will be approved by the RSC in accordance with the most recent approved NPCC Amended and Restated Bylaws.

A. Management of the NPCC Regional Standards Process

The RSC is responsible for managing the standards process for development of standards, VRFs, VSLs, definitions, variances and interpretations in accordance with the NPCC Regional Reliability Standard Process Manual, NERC and FERC documentation. The RSC is responsible for ensuring the quality of all Standards related materials.

The RSC is responsible for administering the Cost Effectiveness Analysis Procedure "CEAP" to determine if a proposed Regional Standard is cost effective, on a requirement by requirement basis in achieving its reliability objective(s).

The RSC will be available to advise the NPCC BOD on any and all standards related matters.

All RSC Regional Standard related decision making activities will be approved or rejected by a vote as outlined in the NPCC Amended and Restated Bylaws as they pertain to quorum and voting rules.

B. Management of the NPCC Directory and Criteria Process

The RSC manages and has oversight of the processes for development of NPCC Directories and Criteria. The RSC is responsible for ensuring the quality of all Directory and Criteria related materials. RSC will provide groups generating documents Quality Review guidance, and guidance on how to generate the documents and administer the NPCC Directory Development Procedure.

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

C. NERC Reliability Standards

The RSC will:

- Provide NPCC review and coordinate the submission of NPCC comments to existing and developing NERC Reliability Standards when posted for NERC "Open Process Review."
- Provide a forum for NPCC to participate, solicit, and provide Regional comments as new Standard Authorization Requests (SARs), and their respective Reliability Standards, are developed in accordance with the NERC Standard Processes Manual.
- Identify upcoming issues associated with new NERC Reliability Standards and their potential impact on the NPCC Region, (i.e. Regional Difference).
- Propose solutions or guide the development of the Standards through effective and timely comments and soliciting NPCC participation on the SAR and Reliability Standards drafting teams.
- Develop and maintain a Web-Based Database for tracking and scheduling Standards development activities from a Regional perspective.
- Target a wider range of participants in the standard commenting process. Develop databases and e-mail list servers to engage more members and to elicit different perspectives.
- Conduct the process for notification, solicitation, commenting on and for proposing revisions to Standards using the NPCC Triage Process.
- Follow up on proposed and adopted changes to the NERC Standard Processes Manual and Rules of Procedure, as they apply to Reliability Standards, and provide NPCC members with basic information (or pointers to the NERC Website) for a common understanding of the process.
- Coordinate the activities of NPCC members on standard drafting teams and ensure sufficient regional participation on such teams.
- The RSC will review draft NERC CANs for Reliability Standard and compliance implications after receiving CC input, and submit comments to NERC.

D. FERC Activities Affecting Standards

The RSC will review FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) relating to Reliability Standards. The RSC will discuss, develop comments, and if necessary submit the comments to FERC on behalf of NPCC.

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

January 18, 2012

To: NPCC Board of Directors

From: Stanley E. Kopman
Assistant Vice President, Compliance Registration and Enforcement

Subject: Draft Revised Scope of the NPCC Compliance Committee

Dear Members:

Attached please find, for your review and approval, the draft revised scope of the NPCC Compliance Committee. This draft was endorsed by the NPCC Compliance Committee on January 11, 2012.

Sincerely,

Stanley E. Kopman
Assistant Vice President, Compliance Registration and Enforcement
NPCC, Inc.

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Scope of Work
For
NPCC Compliance Committee (CC)

Committee Mission

The NPCC Compliance Committee (CC) shall be charged with providing objective stakeholder policy input to the NPCC Compliance Monitoring and Enforcement Program (CMEP) and the NPCC Criteria Compliance Enforcement Program (CCEP).

The NPCC CMEP encompasses compliance monitoring, assessment, and enforcement of NERC Reliability Standards and NPCC Regional Reliability Standards. The NPCC CCEP encompasses compliance monitoring, assessment, and enforcement of the NPCC Reliability Criteria. The CC shall provide an oversight role of the NPCC Compliance Staff's implementation of the CMEP. In this oversight role, the CC will review and endorse the processes used by the NPCC Compliance Staff to implement the CMEP. The CC shall be responsible for final approval of compliance assessments related to the CCEP, which includes non-monetary sanction recommendations.

Committee Functions

The CC is charged with the following responsibilities related to the CMEP:

1. Review and approve NPCC Compliance Procedures for implementing the CMEP.
2. Conduct annual evaluation of the NPCC Compliance Staff's implementation of the NPCC CMEP.
3. Review and endorse the processes used by NPCC Compliance Staff for noncompliance assessments and determination of sanctions consistent with the ERO Sanctions Guidelines related to NERC and NPCC Regional Reliability Standards.
4. Provide final approval of compliance assessments related to the NPCC CCEP to the Reliability Coordinating Committee (RCC).
5. Forward any identified violations of CCEP criteria and recommended sanctions to the NPCC Enforcement Panel for processing.
6. Review and endorse annual NPCC CMEP Implementation Plan as presented by NPCC Compliance Staff.
7. Review and endorse any proposed modifications or revisions to the NPCC CMEP as presented by NPCC Compliance Staff or NERC.
8. Impanel the Hearing Body to resolve contested compliance and/or sanction and penalty determinations related to the CMEP in accordance with the NPCC Bylaws. Oversee activities of any subcommittees, working groups, or users groups that are formed.
9. Provide regular reports to the NPCC Board of Directors on all matters related to the NPCC CMEP.

Committee Structure

The Committee will consist of representatives from the seven voting sectors as described in the Amended and Restated Bylaws of Northeast Power Coordinating Council, Inc.("NPCC").

The Committee will be chaired by the Assistant Vice President of Compliance and Registration or his /her designee. The Committee will elect a vice chair from its members.

The Committee will be bound by the same quorum and voting rules applicable to the NPCC Board of Directors and described in the Amended and Restated Bylaws of Northeast Power Coordinating Council, Inc. ("NPCC") while conducting CC business.

The Hearing Body will consist of an independent Hearing Officer and the two (2) Independent Directors of the NPCC Board. In order to impanel the Hearing Body, the CC chair will notify the two (2) Independent Directors of a hearing request and the CC will select the independent Hearing Officer. The Hearing Body will utilize a simple majority vote to resolve issues. This voting rule, along with the structure of the Hearing Body, fully supports the requirement that no two stakeholder sectors may control, and no single stakeholder may veto, a matter before the Hearing Body.

DRAFT

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Date: January 18, 2012

To: NPCC Board of Directors

From: Guy V. Zito
Assistant Vice President – Standards
Chair, Regional Standards Committee

Subject: Regional Standards Committee (RSC) Transmittal to the NPCC BOD, 2012-2013 RSC Work Plan

The NPCC RSC respectfully submits the attached 2012-2013 draft RSC Work Plan for BOD consideration and approval. The RSC Work Plan is responsive to the NERC 2012-2014 NERC Reliability Standards Development Plan that outlines the ERO's schedules and activities as they are related to the individual Standards Projects and also the directives issued to NPCC regarding the development of Regional Standards and comports with the NERC "One Enterprise" model. The Work Plan will also be consistent with the 2012 and 2013 NPCC Business Plan and Budgets currently under development.

The Work Plan contains activities which support NERC's Results Based initiative, and reflect NPCC's continued commitment to support NERC's standards development activities. The Work Plan also includes support of compliance related matters which affect standards' requirements and the development or revision of standards.

The Work Plan also reflects the significant amount of work that has the RSC has assumed due to NERC's issuances of requests for interpretations, and Compliance Application Notices (CANs). The NPCC RSC is devoting the time necessary to properly review and evaluate these, as well as all other relevant NERC and FERC items related to standards which require review and comment.

cc: Regional Standards Committee

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Northeast Power Coordinating Council, Inc.
Regional Standards Committee
Work Plan for Calendar Years 2012-2013

The following Regional Standards Committee (RSC) activities planned for 2012 -2013 will be consistent with the NPCC 2012 and 2013 Business Plans and Budgets, Organizational Goals, and also will continue to be supportive of the Results Based Standards efforts currently underway. Also, the plan will be responsive to the new NERC Reliability Standards Development Process, containing expedited schedules with rapid and successive revision and ballot provisions.

Core Reliability Standards Functions

- Review, promote, and support the Results Based Standards initiative and continuation of standards developmental work going on within NERC.
- Promulgate the Results Based Standards initiative throughout the Northeast.
- Refine, finalize, and implement Cost Effective Analysis Procedure and apply to NPCC regional standards development. Promote NERC consideration and adoption of NPCC Cost Effective Analysis Procedure.
- Develop and/or utilize NERC tools to incorporate the "Results Based" types of requirements into the NPCC Regional Standards under development.
- Review and participate in the Regional Standards development process, and develop NPCC Regional Reliability Standards on a schedule as directed by NERC and the reliability related needs of the Region.
- Coordinate NPCC Regional Standards development with the development of standards appearing in the NERC reliability standards development plan.
- Coordinate the NPCC participation in the review and the revision of the CIP standards per Order 706.
- Monitor and coordinate NERC's CEO top reliability related issues and priorities.
- Coordinate the NPCC participation in the review and the revision of NERC Standards per Order 693 addressing Directives from the Commission and any Provincial Regulatory directives.
- Review and revise the Regional Reliability Standards Development Procedure for filing with the FERC as may be necessary to promote consistency and support the ERO One Enterprise model.
- Manage the Regional Reliability Standards development processes.
- Manage the development and revision of the Regional Reliability Directories
- Continue to assist the NPCC Compliance Committee by developing Phase 2 of the Directory Project involving revision of criteria language into requirements that are measureable and conducive to compliance assessments.
- Coordinate and provide input to the development and prioritization of ERO reliability standards within NERC reliability standards work plan.
- Conduct thorough reviews of all NERC standards being developed or revised and coordinate comments for Northeastern North America utilizing the NPCC Triage Process as necessary to ensure timely reviews.
- Ensure the NERC standards have measurable "Results Based" requirements.
- Develop and submit Standard Authorization Requests for revisions when necessary to improve and address reliability related issues for approved or draft standards.

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Regional Standards Committee
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- Develop comments and ballot recommendations or "issues statements" for all NERC standards under development.
- Review and develop ballot recommendations for all NERC Formal Interpretations to standards.
- Review posted Compliance Application Notices "CANs" and coordinate NPCC Member comments and submissions.
- Participate in NERC and NPCC Quality Reviews of standards on a schedule as determined by NERC, NPCC and government regulatory authorities.
- Provide guidance for NPCC regional standard drafting teams in critical areas of Results Based Standards, Violation Severity Level, and Violation Risk Factor development as well as in ensuring quality.
- Review and monitor the NERC definition of Bulk Electric System with respect to existing standards and the impact on the northeast with assistance from the NPCC Task Forces to determine if any Regional Differences need to be initiated or revisions to Regional Standards.
- Review of North American Energy Standards Board (NAESB) postings and activities for potential conflicts with reliability related issues and objectives.
- Review FERC Orders and Provincial rulings pertaining to standards and standards development activities to ensure directives are addressed.
- Participate in the regional standards development activities and processes in other regions within the Eastern Interconnection.
- Participate in the proceedings of various NERC groups to contribute to the continual improvement to NERC standards and processes. These groups include but are not limited to:
    - NERC Standards Committee
    - NERC Standards Committee Process Subcommittee
    - NERC Standards Committee Communications Subcommittee
    - NERC Functional Model Working Group
    - NERC Regional Standards Group
    - NERC SAR and Standards Drafting Teams

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NERC ERO Reliability Standards Activities

The following Standards are scheduled for revision and or development in the latest draft of the "NERC Reliability Standards Development Plan: 2012 – 2014", and include the following Standards Projects. NERC has recently undertaken a prioritization of the projects into three classes; Reliability, Time Sensitivity, and Practicality and the below list is subject to change. Also note that some standards appear in more than one project due to potential retirement issues and potential division of requirements of that standard into multiple other standards and projects.

Standards Projects Scheduled for 2012-2014 development activity include a total of 36 Projects of Continent-wide Standards Development:

- **2006-06 Reliability Coordination. This project ranked #13 in Reliability Priority.**
- **2007-02 Operating Personnel Communication Protocols. This project ranked #5 in Reliability Priority.**
- **2007-03 Real-time Transmission Operations. This project ranked #4 in Practicality Priority.**
- **2007-06 Protection System Coordination. This project ranked #4 in Reliability Priority.**
- **2007-07 Vegetation Management.**
- **2007-09 Generator Verification.**
- **2007-12 Frequency Response. This project ranked #10 in Reliability Priority, and was tied for #2 in Time Sensitivity Priority.**
- **2007-17 Protection System Maintenance and Testing. This project ranked #3 in Reliability Priority.**
- **2008-06 Cyber Security - Order 706. This project ranked #1 in Reliability Priority.**
- **2009-01 Disturbance and Sabotage Reporting. This project ranked #7 in Reliability Priority.**
- **2010-05.1 Phase 1 of Protection Systems: Misoperations. This project ranked #8 in Reliability Priority.**
- **2010-07 Generator Requirements at the Transmission Interface. This project ranked #13 in Practicality Priority, and was tied for #2 in Time Sensitivity Priority.**
- **2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves.**

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This project ranked #1 in Time Sensitivity Priority, and #2 in Practicality Priority.

- **2010-17 Definition of Bulk Electric System. This project ranked #10 in Reliability Priority, and was tied for #2 in Time Sensitivity Priority.**
- **2008-02 Undervoltage Load Shedding. This project ranked #14 in Reliability Priority, and will be started upon the completion of 2006-06 Reliability Coordination.**
- **2009-02 Real-time Monitoring and Analysis Capabilities. This project ranked #1 in Practicality Priority, and will be started upon the completion of 2007-03 Real-time Transmission Operations.**
- **2009-03 Emergency Operations. This project ranked #3 in Practicality Priority, and will be started upon the completion of 2008-06 Cyber Security – Order 706.**
- **2010-01 Support Personnel Training. This project ranked #15 in Reliability Priority, and will be started upon the completion of 2009-01 Disturbance and Sabotage Reporting.**
- **2010-05.2 Phase 2 of Protection Systems: SPS and RAS. This project ranked #11 in Reliability Priority, and will be started upon the completion of the first phase of the project, 2010-05.1 Phase 1 of Protection Systems: Misoperations.**
- **2010-13.2 Phase 2 of Relay Loadability: Generation. This project has been identified as having a higher priority, as it has a FERC deadline. While this was accounted for in the Prioritization, the SC agreed that this should take precedence over the 5-year review projects considered in the Prioritization. This project will be started upon the completion of 2007-12 Frequency Response.**
- **2012-04 Protection System Commissioning Testing. This project ranked #9 in Reliability Priority, and will be started upon the completion of 2007-17 Protection System Maintenance and Testing**
- **2007-11 Disturbance Monitoring. This project will start upon completion of 2010-17 Definition of Bulk Electric System.**
- **2008-01 Voltage and Reactive Panning and Control. This project ranked #6 in practicality, and will start upon completion of 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves**
- **2008-12 Coordinate Interchange Standards. This project will start upon completion of 2010-07 Generator Requirements at the Transmission Interface.**
- **2009-07 Reliability of Protection Systems. This project ranked #2 in Reliability Priority, and will start upon completion of 2007-06 Protection System**

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Coordination.

- **2010-14.2 Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent. This project will start upon completion of 2009-02 Real-time Monitoring and Analysis Capabilities.**
- **2012-01 Equipment Monitoring and Diagnostic Devices. This project will start upon completion of 2007-02 Operating Personnel Communication Protocols.**
- **2012-06 Generator Capabilities, This project ranked #6 in Reliability Priority, and will start upon completion of both 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves and 2007-09 Generator Verification.**
- **2009-04 Phasor Measurements. This project will start upon completion of 2009-03 Emergency Operations.**
- **2009-05 Resource Adequacy Assessments. This project will start upon completion of 2012-04 Protection System Commissioning Testing.**
- **2010-03 Modeling Data. This project will start upon completion of 2008-01 Voltage and Reactive Panning and Control.**
- **2010-04 Demand Data. This project will start upon completion of 2010-05.2 Phase 2 of Protection Systems: SPS and RAS.**
- **2010-08 Functional Glossary Model Revisions. This project will start upon completion of 2010-01 Support Personnel Training.**
- **2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings. This project will start upon completion of the second phase of this project, 2010-13.2 Phase 2 of Relay Loadability: Generation.**
- **2010-16 Definition of System Operator. This project will start upon completion of 2012-04 Protection System Commissioning Testing.**
- **2012-05 ATC Revisions - Order 729. This project will start upon completion of 2008-12 Coordinate Interchange Standards.**

In addition there are another 12 projects in the latest draft of the NERC Reliability Standards Development Plan scheduled to start beyond 2013, some of which have not been prioritized and may affect the list above. The total number of standards projects currently listed in NERC's is 48.

Additional Priority Projects (near completion):

- **Project 2006-08 Transmission Loading Relief**

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- **Project 2007-04 Certifying System Operators**
- **Project 2010-17 Definition of Bulk Electric System and conforming changes to NERC Rules of Procedure**
- **PRC-002-NPCC NPCC UFLS Regional Standard**

NERC will also continue to coordinate standards development activities with the business practices developed by the North American Energy Standards Board (NAESB).

NPCC Regional Standard and Directory Activities and Requirements

- Develop the following regional standards and requirements utilizing the NPCC Regional Reliability Standards Development Procedure if necessary and directed by the ERO or as needed in response to the revision of the ERO standard(s);

    - Special Protection Systems Standard
    - Regional Reserve Sharing Groups Standard

- NPCC regional Underfrequency Load Shedding Standard, complete development and once approved, compile historical documentation and submit to NERC BOT for approval
- Develop any required responses to regulatory inquiry for NPCC Regional Disturbance Monitoring Standard and provide to FERC and the applicable Provincial regulatory authorities for their information or approvals, as may be required, i.e. data requests, filings to address directives etc.
- Develop the necessary regional standard filings with the FERC and applicable Provincial regulatory authorities for the NPCC Underfrequency Load Shedding Standard
- Address any outstanding issues with the regulatory authorities in the US and all applicable Provincial authorities for regional standards or NPCC Directories
- Draft Regional Standards Authorization Requests, RSARs
- Produce initial drafts of regional standards for Drafting Teams to start with
- Develop proposed standards utilizing regional technical committees as assigned by the NPCC RCC.
- Work with the NPCC CC to develop the necessary compliance elements of the standards, i.e. Violation Severity Levels
- Coordinate Directory criteria requirements with Regional Standards requirements to ensure no inconsistencies exist and identify potential areas for improvement
- Develop filing for the Directories for New York State Public Service Commission to fulfill obligations for the “Carve-out” outlined in Order 672 of mandatory adherence to more stringent regional criteria for NY State
- Develop filings of Directories as required with the Provincial regulators per the various Memorandums of Understanding

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RSC Ongoing Activities

- Implement technical aspects related to the implementation of the Energy Policy Act of 2005, focusing on Standards/Criteria Development, and related FERC and ERO requirements.
- Implement the NPCC CEAP and apply initially to the developing regional standards and investigate application to the draft ERO continent wide standards.
- Review the Standards Authorization Requests, Standards, and Interpretations and provide comments as well as participate in the NERC process.
- Implement the NPCC Triage Process and ensure that the appropriate NPCC Task Forces review NERC issuances, and provide input to support a consensus opinion.
- Solicit technically qualified candidates from Northeastern North America to participate on each of the NERC drafting teams and additional members to the regional drafting teams and ensure sufficient regional representation exists on the drafting teams.
- Review FERC rulings and communicate the rulings to the NPCC members and coordinate issues for the Members.
- Participate in ballots for ERO standards and provide recommended comments and ballot positions to the NPCC Members of the NERC Registered Ballot Body.
- Review and develop comments on FERC Notice of Proposed Rulemaking (NOPR) for any and all standards-related issues as appropriate.
- Use the NPCC Triage Process to evaluate proposed standards utilizing regional technical committees, task forces and working groups.
- Educate and notify stakeholders and regulators about issues related to standards development.
- Provide a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC) and NPCC Task Force on Infrastructure Security and Technology (TFIST).
- Achieve NPCC reliability goals and objectives by initiating and efficiently completing standards development activities.
- Leverage internet and web based tool functionality to ensure interregional consistency, uniformity, and quality of regional reliability standards.
- Establish long-term strategy for standards improvement and initiate implementation.
- Ensure the topics addressed by the reliability standards parallel changing industry needs.
- Business Practices Interface
    - Coordinate the review of standards with NPCC members of the North American Energy Standards Board, details above.
    - Identify potential market issues for Regional Standards through NPCC Reliability Coordinating Committee (RCC) reviews.
- Process Improvement
    - Identify efficiencies for a coordinated NERC standards development process and NPCC Regional Standards Development Procedure and recommend revisions as applicable.
    - Participate in the revision and redrafting of the NERC rules and procedures related to standards development such as, but not limited to:

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- The NERC Functional Model Working Group
- The NERC Regional Standards Group
- The NERC Standards Committee
- The NERC Standards Committee Process Subcommittee

  - Establish goals/targets for NERC and NPCC standards procedure improvement.
- Streamline and improve the regional standards process and continue to enhance program tools.
- Communications
  - Automate notifications process to assure awareness of dates and proceedings of all standard development activities.
  - Strengthen the relationship with the industry's technical committees to ensure adequate input to standards development.
  - Sponsor NPCC Workshops and participate in NERC/ERO workshops to promote awareness and educate the industry of standards-related activities.
  - Promote the reliability objectives of the NERC standards as appropriate to the NPCC members of the NERC Registered Ballot Body.
  - Educate and inform industry stakeholders through web based tools such as "Webinars" and participation in NERC Reliability Standards Workshops, as necessary.
  - Update and inform governmental regulators and/or authorities on the standards development work plan and processes through individual project discussions and annual meetings/conferences.
  - Develop standards program communications that support NERC's overall communications platform.
  - Develop and maintain NPCC Reliability Directories that will enable users, owners and operators of the international bulk power system in the Region the ability to apply reliability requirements in NERC and NPCC as well as the more stringent NPCC regionally-specific criteria.
  - Identify future regional standard opportunities by developing a set of Regional Reliability Directories incorporating the ERO Reliability Standards, Regional Standards and regionally-specific more stringent Criteria.
  - Accomplish all directives of ERO and governmental and/or regulatory authorities with regard to regional standards development and procedures.
  - Adhere to and surpass the ERO work plan milestones, when practical, as they pertain to targets for the regional standards.

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Date: January 18, 2012

To: NPCC Board of Directors

From: Guy V. Zito
Assistant Vice President – Standards
Chair, Regional Standards Committee

Subject: Regional Standards Committee (RSC) Status Report to the NPCC Board of Directors

Since the last NPCC BOD Meeting Report, RSC activities have included, but not been limited to, the following:

- NPCC Directory development:
  - NPCC Directory #1 Phase II, Design and Operation of the Bulk Power System was developed and presented to the TFCO. CP11 working group is revising the Directory to facilitate the NPCC Criteria Compliance Enforcement Program (CCEP)
  - NPCC Directory #5 Phase II, Operating Reserve remains under development with TFCO.
  - NPCC Directories #9 and #10 Phase II, pertaining to generator capability verification were completed and balloted and approved by the NPCC Full Members.
  - A new Directory on Regional Reserve Sharing has been assigned by the RCC to TFCO. A first draft has been developed and is under review with the TFCO for refinement and development. This directory will be the basis for the standard on reserve sharing that the ERO directed NPCC to develop. CO1 is conducting a review of the reliability impact of reserve sharing.
  - RSC has also completed and approved the NPCC Directory Development Procedure which codifies how to develop, revise and maintain NPCC's Directories.
  - RSC has also completed a new and revised NPCC Glossary document. The Glossary highlights inconsistencies between NERC and NPCC terms to facilitate consistency and reduce duplicity between ERO and Regional definitions.

- The RSC through NPCC staff is preparing materials for recent stakeholder and BOD approved NPCC UFLS standard (PRC-006-NPCC-01) to file with the FERC. In addition

the standard has received NERC staff endorsement and NPCC staff, in conjunction with NERC staff, also has developed the agenda item for the February BOT meeting where the standard's approval will be sought.

- RSC completed development of a Cost Effectiveness Analysis Procedure "CEAP" to evaluate new and revised standards to ensure they meet their reliability purpose and identify the costs associated with implementation. Comments on the process were received from the industry through open process postings as well as NERC staff. In addition, the new NPCC CEAP was applied to the NPCC UFLS regional standard and the results posted on the NPCC website during ballot of that standard to provide the industry with information about the costs and effectiveness of the standard. In 2012 it is envisioned that NPCC will pilot this new CEAP by applying it to a NERC continent wide standard and sharing the results with industry and the NERC Standards Committee. This could be a potential "first step" to provide the industry with information on cost and effectiveness of a new standard to achieve a reliability objective. RSC will continue to gather input from various industry groups such as, but not limited to, North American Generator Forum, North American Transmission Forum and the ISO-RTO Council as the opportunity arises.

- The NPCC Disturbance Monitoring, (DM) Regional Standard PRC-002-NPCC-01 was approved without Directive by the FERC in October 2011. Since that time the NERC BES definition has received approval and the RSC has begun reviewing issues being raised by stakeholders due to the expanded applicability of the BES revised definition. The ERO is engaged in filing the standard with the applicable Provincial governmental authorities.

- The NPCC Special Protection System Review, (SPS) Regional Standard PRC-012-NPCC-01 initial draft has been drafted. Further direction from the NERC Drafting Team will be provided before the draft moves forward.

- The NPCC RSC has also participated on, and provided input to the NERC Standards Committee and Standards Committee Process Subcommittee. Of interest to NPCC are:

    - RSC is assisting with refining the Compliance Application Notice process and providing comments to NERC. Also there is activity in the area of an Informal Guidance Process in an attempt to provide industry with guidance rather than seeking numerous interpretations.
    - Continued review of potential revisions to Version 5 of the NERC Functional Model to capture emerging issues with Demand Side Resources as they replace the reserve obligations of Balancing Authorities.
    - Education of the NPCC membership and stakeholders on attributes of the new NERC Reliability Standards Process Manual which has been approved by FERC and is being implemented as well as changes to the NERC Rules of Procedure, through outreach and a Compliance and Standards Workshop held in December of 2011.
    - RSC has implemented its "Triage Process" to address the urgency and frequency of NERC standards related activities. RSC will continue to review and revise this process to continually strive to increase efficient utilization of NPCC's resources.

- RSC assisted and continues to assist with refinement and implementation of the NERC Prioritization tool being used to evaluate and prioritize standards projects.
- RSC is working on revising the existing NERC Self Nomination process to ensure true Subject Matter Experts are populating the NERC Drafting Teams to deliver the highest quality standards possible.
- RSC has developed and posted a first draft of a revised Regional Standards Process Manual. The RSC anticipates completing a revision by the end of 2012 however NERC is currently engaged in a major standards development process overhaul which may affect and influence how NPCC develops their regional standards.

- The RSC has worked with the NERC Standards Drafting Teams, and appropriate NPCC Task Forces and Working Groups to address regional concerns and developed ballot/re-ballot recommendations or provided issue statements for the following NERC Reliability Standards, efforts and Interpretations:

  - Project 2007-03: Real-time Operations
  - Project 2007-03: Real-time Operations, non-binding poll VRFs and VSLs
  - Project 2010-07: Generator Connection Requirements at the Transmission Interface.
  - Project 2010-07: Generator Connection Requirements at the Transmission Interface, non-binding poll VRFs and VSLs
  - Project 2008-06: CIP V5
  - Project 2008-06: CIP V5 Implementation
  - Project 2008-06: CIP V5 Definitions Dec 2011
  - Project 2009-01 Disturbance And Sabotage Reporting
  - Project 2009-01 Disturbance And Sabotage Reporting non-binding poll VRFs and VSLs
  - Project 2007-12 Frequency Response Initial Ballot
  - Project 2007-12 Frequency Response Initial Ballot non-binding poll VRFs and VSLs

- Continue to monitor emerging issues such as High Impact Low Probability, Smart Grid, Renewable Resources, and CIP development.

- Reviewed and coordinated consensus NPCC comments utilizing the NPCC subject matter experts in the task forces and working groups, to the extent possible, and transmitted comments to NERC for the projects as listed on the NPCC Website- http://www.npcc.org/documents/regStandards/Comments.aspx :

- NPCC RSC continues to participate in the activities of the NERC Regional Standards Group RSG, coordinating standard development activities with the other Regions to achieve consistency, uniformity and promote reliability objectives throughout the Interconnections in North America. The group currently is engaged in scheduling of NERC's resources to evaluate regional standards and coordinating standards requirements.

- NPCC monitors NERC, NAESB regional activities by participating in bimonthly conference calls and reviews the development of any issues for any potential reliability impacts.

- NPCC is supporting the NERC Balancing Authority and Reliability Based Control Drafting Team efforts “BARC” and ensuring coordination exists between this team and the reserve sharing efforts underway in draft Directory and Standard documents at NPCC.

- NPCC RSC is also coordinating the commenting review and revision of the Version 5 of the CIP standards currently in the development stage at NERC. The standards involve addressing outstanding FERC Directives appearing in Order 706. The RSC in conjunction with TFIST developed a ballot recommendation to reject the standards and submitted suggested revisions which would enable our members and stakeholders to support the standards. NPCC is working with the standard drafting team to effectuate those changes.

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January 18, 2012

To: NPCC Board of Directors

From: Stanley E. Kopman
Assistant Vice President, Compliance Registration and Enforcement

Subject: Draft 2012-13 Work Plan of the NPCC Compliance Committee

Dear Members:

Attached please find, for your review and approval, the draft 2012-13 Work Plan of the NPCC Compliance Committee. This draft was endorsed by the NPCC Compliance Committee on January 11, 2012.

Sincerely,

Stanley E. Kopman
Assistant Vice President, Compliance Registration and Enforcement
NPCC, Inc.

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
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NPCC Compliance Committee (CC)
2012-2013 Work Plan

The 2012-2013 Compliance Committee (CC) Work Plan defines the following aspects of the Compliance Committee:

- Core Responsibilities
- On-going activities
- Scheduled additional activities for 2012
- Partial listing of 2013 projected additional activities

The CC activities planned for 2012 -2013 will be consistent with the approved NPCC 2012 Business Plan and 2012 Organizational Goals. These in turn are intended to be consistent with the 2013 NPCC Business Plan and the 2013 NPCC Organizational Goals that are under development.

Core Responsibilities

The CC is charged with core responsibilities related to the NPCC Compliance Program that includes (i) the NPCC Compliance Monitoring and Enforcement Program (CMEP) for NERC Reliability Standards and NPCC Regional Reliability Standards; and (ii) the NPCC Criteria Compliance and Enforcement Program (CCEP) for the region-specific NPCC Criteria as follows:

- Provide objective stakeholder policy input related to:
  - the CMEP in the United States
  - the CCEP
- Provide NPCC perspective to both the NERC Compliance and Certification Committee (CCC) and the ERO Compliance and Enforcement Management Group (ECEMG) for matters related to the NERC CMEP.
- Assess the performance of the NPCC Compliance Staff's implementation of the Compliance Program, including the endorsement of the processes used for non-compliance assessments and enforcement determinations.
- Approve compliance assessments and sanction recommendations related to CCEP.
- Promote the continued education of stakeholders as to their responsibilities related to the CMEP and CCEP.

DRAFT

On- Going Activities

The CC will conduct the following on-going activities:

- Review and provide comments on annual NPCC CMEP Implementation Plan as presented by NPCC Compliance Registration and Enforcement and NPCC Compliance Audits and Investigation teams.
- Identify aspects of the CMEP that will comprise CC annual evaluation of the NPCC Compliance Staff's implementation of the NPCC CMEP. These evaluations will include team assessments of the Staff's implementation of specific portions of the CMEP. The assessments will focus on identifying strengths and recommendations that will enhance the Staff's implementation of the CMEP.
- Impanel the Hearing Body to resolve contested compliance and/or sanction and penalty determinations in accordance with the NPCC Bylaws.
- Review and provide comments on any proposed modifications or revisions to the CMEP as presented by NPCC Compliance Staff or NERC.
- Review and develop consensus comments on FERC Notice of Proposed Rulemaking (NOPR) for any compliance program related issues as appropriate.
- Conduct periodic reviews of the CMEP hearing process and procedures.
- Review, modify, and approve annual CCEP Implementation Plan noting any revisions from the prior year's program.
- Review technical issues related to identified potential and/or confirmed compliance violations of NPCC Criteria. These technical issues will be reviewed by the NPCC CC to provide clarifying information for CCEP implementation revisions, identifying lessons learned, and/or developing recommended changes to the CCEP implementation processes or NPCC Criteria.
- Review and provide final approval of compliance assessments related to the CCEP, including approval of non-monetary sanction recommendations.
- Review and approve NPCC Compliance Procedures developed for implementing the various aspects of the CMEP and CCEP.
- Propose, review, and approve any modifications or revisions to the CCEP.
- Provide regular reports to the NPCC Board of Directors on all matters related to the NPCC CMEP and CCEP activities.
- Review and appropriately modify the CC Work Plan on an annual basis.

Scheduled 2012 Additional Activities

During 2012 the CC is scheduled to conduct the following additional activities:

Activities related to compliance with NERC Reliability Standards or NPCC Regional Standards

- Provide input to the NERC CCC related to the development of NERC's entity assessment program.
- Conduct an assessment of the NPCC Compliance Staff implementation of the Entity Registration Process to ensure compliance with the NERC Rules of Procedure.
- Continue development of additional CMEP related performance metrics or Key Performance Indicators (KPIs) as guidelines for assessing Compliance activities.

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- Identify potential CMEP areas for improvement and increased efficiency through the use of KPI analysis and propose enhancements to the CMEP based on this analysis on an annual basis.
- Participate in the NERC CCC stakeholder meetings. A CC member (who is not an NPCC Staff member) is the NPCC Regional representative on the NERC CCC. The CC member should also participate on one of the NERC CCC subcommittees that review and recommend changes to NERC CCC programs, processes and the NERC Rules of Procedure (ROP), such as the Procedure Subcommittee (PROCS) or the Organization Registration and Certification Subcommittee (ORCS).
- Identify items for presentation at each of the two 2012 Compliance Workshops.
- Evaluate and explore the CC's role related to compliance program implementation by the Canadian provinces within the NPCC region as the MOUs for each province are approved and implemented.

Activities related to compliance with NPCC Criteria:

- Discuss and determine additional Criteria to be included in CCEP, focusing on the ultimate goal of including all more stringent and more specific NPCC Criteria in the CCEP.
- Develop and approve 2013 CCEP Implementation Plan including the 2013 schedule for compliance submittals.
- Develop, review, and endorse CCEP related performance measures.
- Identify potential areas for CCEP improvement and increased efficiency through the use of KPI analysis and propose enhancements to the CCEP based on the performance measures analysis.

Projected 2013 Additional Activities

The following is a partial list of projected additional activities to be carried out by the CC in 2013:

- Evaluate and implement a long-term strategy for reviewing and revising the NPCC CMEP and NPCC CCEP.
- Conduct evaluation of the NPCC Compliance Staff's implementation of the NPCC CCEP. The assessments will focus on identifying strengths and recommendations that will enhance the Staff's implementation of the CCEP.
- Implement enhancements to CMEP and CCEP that were identified through the analysis of Performance Measures.

Activities listed, for 2012 and 2013 have been developed based on the current planned implementation of the NPCC CMEP, and implementation of the revised NPCC CCEP. Changes to these programs, the NERC CMEP, the NERC Rules of Procedure, or the MOUs with Canadian entities 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 Work Plan will be revised in advance of the Board of Director's annual review. In that event, the revised Work Plan would be forwarded to the NPCC Board of Directors for approval.

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

Date: January 18, 2012

To: NPCC Board of Directors

From: Stanley E. Kopman
Assistant Vice President – Compliance Registration and Enforcement

Sal Buffamante
Assistant Vice President – Compliance Audits and Investigations

Subject: January, 2012 CMEP and Compliance Committee Summary Report

This document provides the NPCC Board of Directors with the latest summary of key regional issues, trends, and other significant events related to the CMEP and associated Compliance Committee activities.

- **Key Issues**

  - The NPCC Staff completed its 2011 Culture of Compliance Survey Initiative. NPCC developed and distributed a total of 165 NPCC Culture of Compliance Surveys, covering all 287 NPCC registered entities. The staff evaluated 100% of the 146 survey responses received. The evaluation consisted of reviewing the material sent by each registered entity, conducting one-on-one assessment phone calls with each survey submitter, rating each registered entity, and identifying Examples of Excellence and Best Practices.

    The initiative is documented in the "Report on 2011 NPCC Culture of Compliance Survey Initiative", which is posted on the NPCC Website. The report includes a compilation of the Examples of Excellence and the Best Practices identified which present potential mechanisms or corrective action programs for registered entities to consider when reviewing or enhancing their internal compliance programs.

    A detailed presentation, on the 2011 NPCC Culture of Compliance Survey Initiative, was made at the 2011 Fall NPCC Compliance and Standards Workshop held on December 14 -16, 2011 and attended by over 200 people.

A follow-up webinar will be held in late January or early February 2012 with all NPCC registered entities to discuss the report in detail.

- NPCC is working with the other Regions and NERC in developing audit approach documents for several reliability standards. Documents completed include MOD-001, MOD-004, MOD-008, MOD-030, COM-002, FAC-003, PRC-005 and PRC-023. Each document includes sections on Audit Approach and Data Retention requirements. These documents enable all regions to employ a consistent approach to audits involving these standards.

    - More audit approach documents are being developed based on the Tier 1 Actively Monitored List of Standards.
    - NPCC gave a presentation for the above at the Fall 2011 NERC ERO Auditors' Workshop at NERC's headquarters in Atlanta. The presentation is also posted on NERC's website under the Compliance; Regional Programs; ERO Workshop tab (Item V-A).

- NPCC has developed documentation of examples of excellence in compliance documentation, posting of evidence and preparedness for audits. NPCC shared this with the other regions and all our registered entities during the fall, 2011 compliance workshop.

- To date NPCC has received 534 Technical Feasibility Exception (TFE) submittals covering over 11,000 assets. All have been accepted for Part A and 442 have had their Part B substantive assessment done and approved. All remaining Part B assessments will be completed within the one year parameter. 48 TFE's have been terminated by the entities.

- **Significant Events/Compliance Violation Investigations**

NPCC is currently operating under Phase II of the Event Analysis Process (EAP) field trial and strongly encouraging that all such events be handled under that process.

Since the start of Event Analysis Process and the subsequent two field trials, NPCC has administered approximately 50 qualifying events as described in the five (5) categories, of the NERC ERO EAP manual, which elevate in severity from Category 1(lower significance) to Category 5 (High significance).

During the time of the two EAP Field Trial periods (Phase I – starting in October of 2010 and continuing through Phase II starting in May of 2011 and still active), of the 50 events processed the majority have been of the Category 1 type with roughly 9 of them raising to the level of a Category 2 event.

Although in its current format the EAP program requires that a compliance self assessment be prepared for only category 2 and above events, NPCC has strongly encouraged that registered entities within its footprint conduct this self assessment or standards review for all qualifying events and will continue to do so.

Although voluntary, the success rate for NPCC entities complying with this has been very high with most all submitting these self assessments to NPCC. It is because of this fact that the opening of any Compliance Violation Investigations has been avoided.

The processing of these events through the EAP has also exhibited not only the culture of Reliability and Compliance of these entities but also afforded the added benefit of producing valuable lessons learned for the industry which may have otherwise been lost had a formal compliance investigation been required.

- **NPCC Violations Identified From December 1, 2012 Through December 31, 2011**

  - Violations in the United States

    16 Notices of Possible Violation have been issued.

  - Violations in Canada

    None

- **Status of NPCC Violations Settlement Activities**

  - 20 violations in the United States and Canada are currently involved in settlement discussions, with various entities.

- **NPCC 2012 Compliance Audit Program**

  - NPCC has scheduled 5 On-Site Audits for 2012.
  - NPCC has also scheduled 10 On-Site CIP audits in 2012.
  - NPCC has scheduled 42 Off-Site audits in 2012; 1 is completed.
  - NPCC has scheduled 3 off-site CIP audits in 2012.
  - NPCC has developed the internal 2012 Spot Check Program schedule, and has targeted 400 spot checks of 85 registered TOPs, TOs, GOs and PSEs. Spot Checks for 2012 include IRO-005-2, Var-001-2, TOP-002-2b, PRC-004-2a and PRC-005-1a.

- All NPCC contract auditors will attend either of the two NERC auditor's workshops, and staff auditors will attend both.

Dec. 2011

NPCC Violation Summary

	Notice of Possible Violation[1]	Dismissal[2]	NAVAPS[3]	NOCV[4]	Settlement Discussion (Ongoing)[5]	Signed Settlement[6]	NOP[7]
FERC Enforceable	16	0	0	4	15	4	7
Canadian	0	0	0	0	5	0	

Table 1

1 Please refer to Table 2 for more details
2 Please refer to Table 3 for more details
3 Please refer to Table 4 for more details
4 Please refer to Table 5 for more details
5 NPCC and registered entities have not signed the settlement agreement
6 Please refer to Table 6 for more details
7 Please refer to Table 7 for more details

NOPV

# of Violations	Standard	Req.#
1	CIP-003-2	2
1	CIP-005-1	2
3	CIP-006-	1,2
3	CIP-007-2a	5,9
2	CIP-008-2	1
1	CIP-009-1	4
2	FAC-008-1	1
3	PRC-005-1	1,2

Table 2

Dismissal

# of Violations	Standard	Req.#

Table 3

NAVAPS

# of Violations	Standard	Req.#

Table 4

NOCV

# of Violations	Standard	Req.#
1	CIP-002-2	3
2	CIP-006-2	2,5
1	CIP-007-1	2

Table 5

Signed Settlement

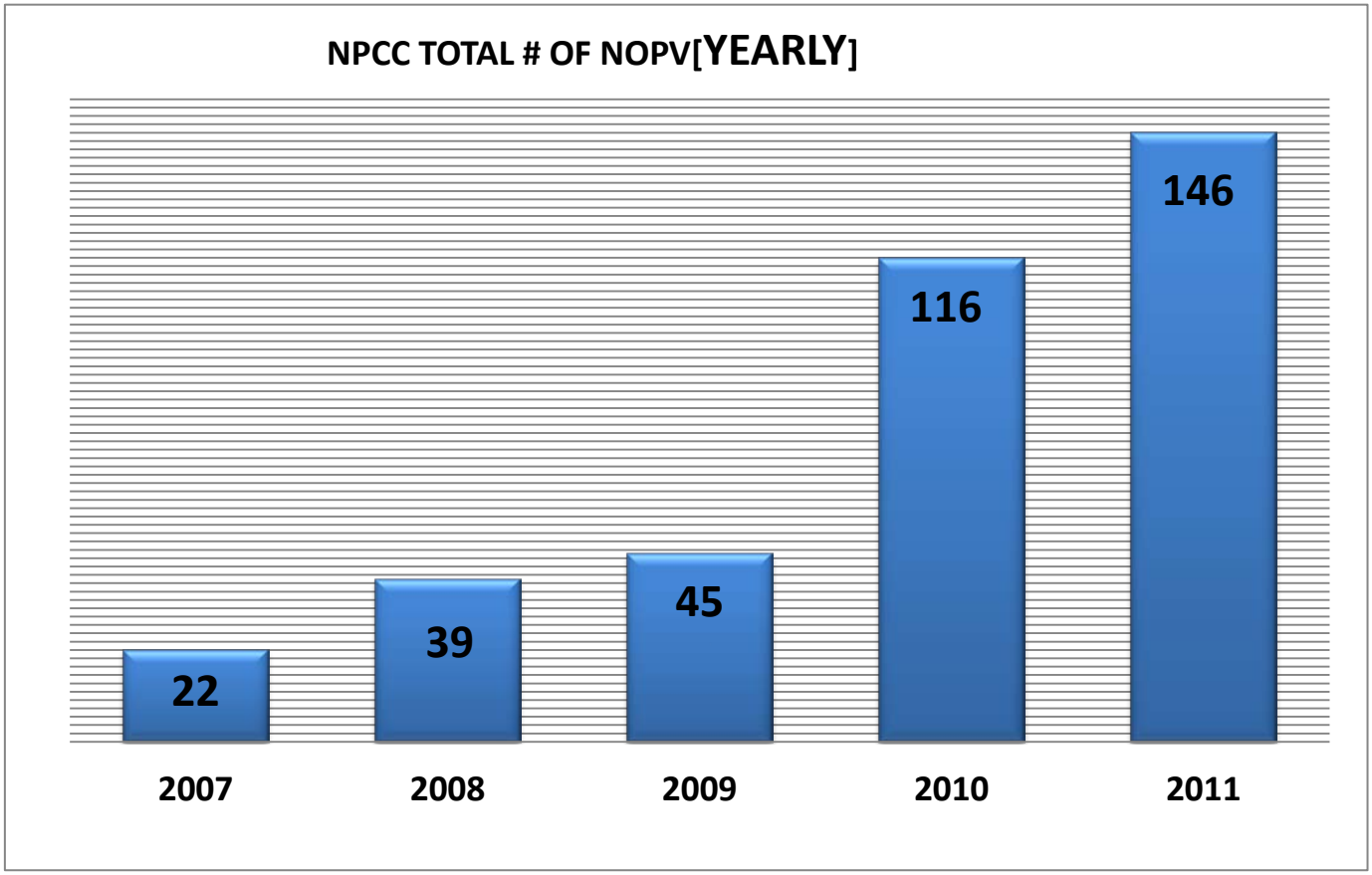
# of Violations	Standard	Req.#
1	CIP-007-2a	2
1	CIP-005-2	2
2	VAR-002-1	1

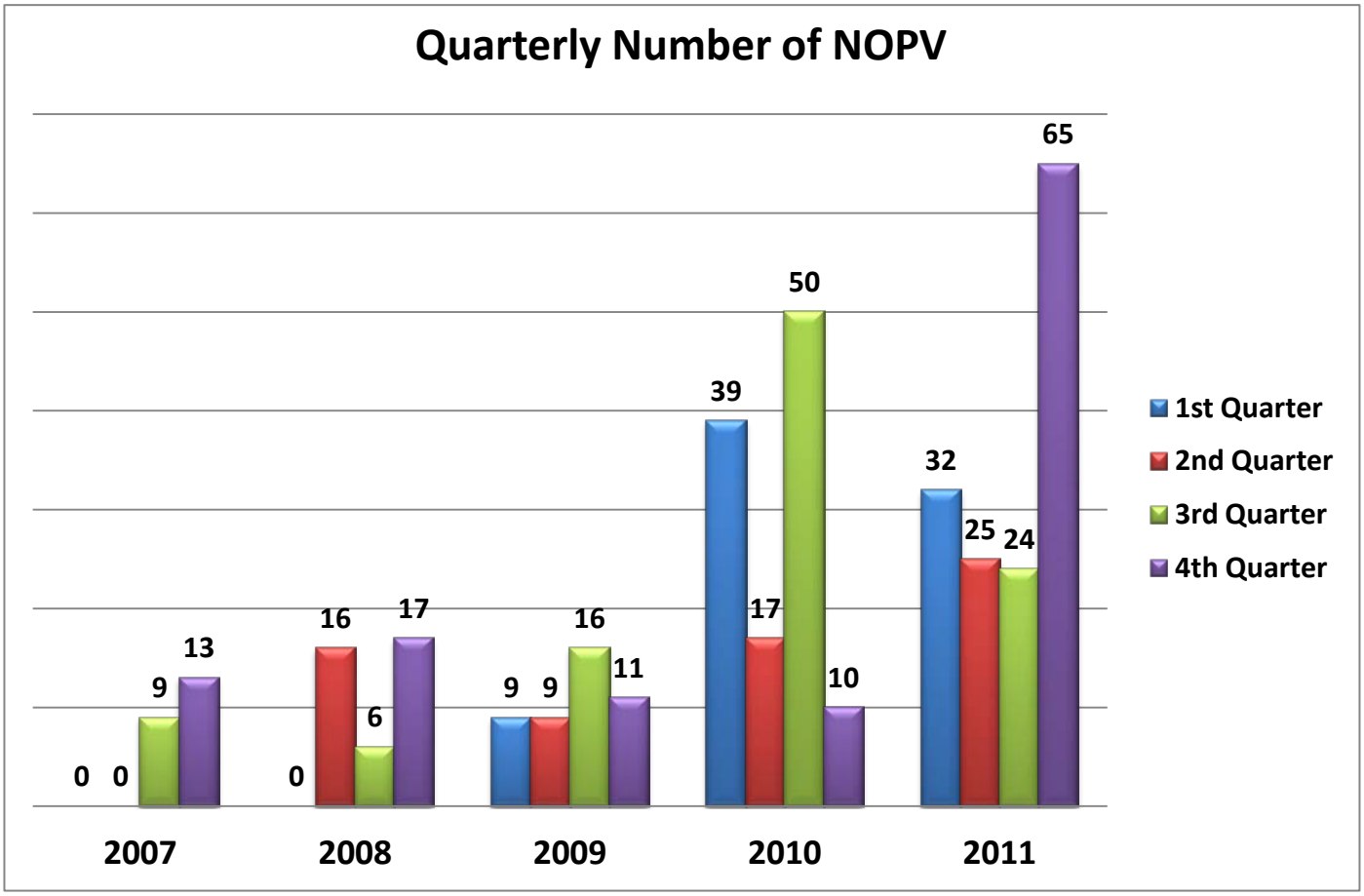
Table 6

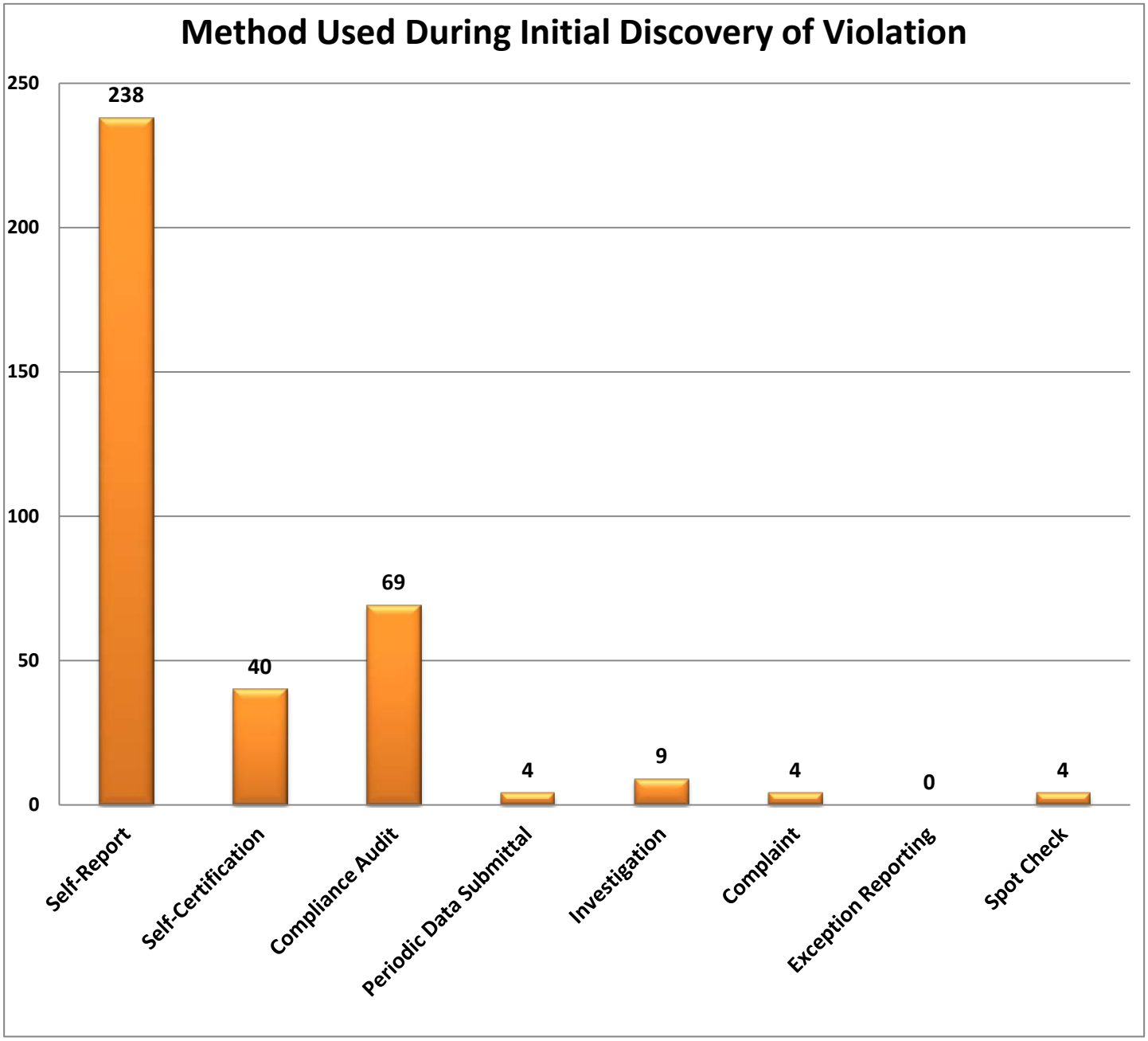
NOP

# of Violations	Standard	Req.#
2	CIP-004-1	4
2	CIP-006-1	1
1	COM-002-2	2
2	PRC-005-1	1,2

Table 7


NPCC TOTAL # OF NOPV[YEARLY]
22
39
45
116
146
2007
2008
2009
2010
2011


Quarterly Number of NOPV
0
0
9
13
0
16
6
17
9
9
16
11
39
17
50
10
32
25
24
65
2007
2008
2009
2010
2011
1st Quarter
2nd Quarter
3rd Quarter
4th Quarter


Method Used During Initial Discovery of Violation
250
200
150
100
50
0
238
40
69
4
9
4
0
4
Self-Report
Self-Certification
Compliance Audit
Periodic Data Submittal
Investigation
Complaint
Exception Reporting
Spot Check

NPCC, Inc.

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

Date: January 18, 2012

To: NPCC Board of Directors

From: Philip A. Fedora - Assistant Vice President – Reliability Services

Subject: NPCC Reliability Coordinating Committee (RCC) Report

The following items were approval at the November 29, 2011 RCC meeting:

- ✓ September 8, 2011 Meeting Minutes
- ✓ RCC Roster Changes
- ✓ Task Force Roster Changes
- ✓ Interim Reviews of Resource Adequacy
  - Maritimes
  - Ontario
  - New York
- ✓ Interim Transmission Reviews
  - New England
  - Quebec
- ✓ Nova Scotia UFLS Implementation Plan
- ✓ NPCC August 14, 2003 Northeast Blackout Study – Task 5 Report
- ✓ 2011 – 2012 NPCC Winter Reliability Assessment
- ✓ New England Comprehensive Review of Resource Adequacy
- ✓ Quebec Comprehensive Review of Resource Adequacy
- ✓ Modification of the temporary Maxcys-Bucksport Type I SPS # 178
- ✓ Endorsement of Directories No. 9 & No. 10
- ✓ 2012-2013 Task Force Work Plans

Following approval of the 2012-2013 Task Force Work Plans, the 2012-2013 RCC Work Plan was finalized, and is attached to be considered for Board approval. The RCC activities planned for 2012 – 2013 are consistent with the NPCC 20112 Business Plan & Budget, the respective 2012-2013 Task Force Plans, and the RCC Scope of activities.

NPCC, Inc.

Reliability Coordinating Committee
Work Plan for Calendar Year 2012-2013

The following Reliability Coordinating Committee (RCC) activities planned for 2012 – 2013 are consistent with the NPCC 2012 Business Plan approved by the NPCC Board June 30, 2011 and the RCC Scope of activities approved by the NPCC BOD on February 3, 2009.

Core Reliability Criteria Functions

- ✓ Review and approve Comprehensive Area Transmission Reviews and Comprehensive Resource Adequacy Reviews brought forth before the RCC.

- ✓ Review and endorse new and revised Regional Reliability Directories and transmit a recommendation to the Full Members of NPCC for their final approval vote, in accordance with the NPCC Regional Reliability Directory Approval Process, and the NPCC Bylaws.

- ✓ As per the filed and approved "NPCC Regional Standards Development Procedure, oversee Task Force drafting and development of NPCC Regional Reliability Standards on the schedule set forth by the NPCC Regional Standards Committee and in accordance with the "NERC Reliability Standards Work Plan 2012 – 2013," as amended from time to time.

- ✓ Enhance the NPCC Regional Criteria Development process by encouraging and implementing procedures allowing for greater interregional interaction, communication and review, and by strengthening the design-based approach in regionally – specific criteria.

- ✓ Include any proposed revision of NPCC Criteria (as per NPCC Reliability Assessment Program (NRAP) schedule) during the development of the related NPCC Reliability Directories.

- ✓ Consider development of new NPCC regionally-specific, more stringent reliability criteria as part of the NPCC Reliability Directory process.

- ✓ Review NPCC Reliability Directories, procedures, guides, white papers, data, website(s) and databases to comply with NERC Reliability Standards and to promote reliability assurance in the NPCC Region.

- ✓ Review proposed NPCC Regional Standards, provide comments, during the period comments are being accepted, to the Regional Standards section of the NPCC Open Process for consideration by the respective NPCC Task Force Drafting Team. Support the NPCC Regional Standards Committee as necessary in the identification of potential reliability related concerns and assist with the

development and revision of Regional Standards, Variances, and/or Requests for Interpretations.

- ✓ Monitor developments at NERC for event related recommendations and incorporate into the NPCC Directories as necessary to meet the reliability objectives of Northeastern North America.

- ✓ Provide technical support to the NPCC Regional Compliance Committee as required in the review of NERC Standards, Compliance Application Notices "CAN"s, performing field tests and providing information for reports such as the NPCC's Cost Effective Analysis Procedure.

Provide technical support to the NPCC Regional Standards Committee's review of NERC Standards.

On-going activities

- ✓ Develop NPCC technical input and positions on NERC and FERC activities.

- ✓ Complete follow-up activities from the NPCC Blackout (2003) Study.

- ✓ Actively participate in the Eastern Interconnection Reliability Assessment Group (ERAG) activities.

- ✓ Actively participate in the established joint technical forum with Reliability *First* Corporation and the Midwest Reliability Organization to assure wide area, inter-regional coordination, by exchanging ideas and practices, including the identification of the need for appropriate near-term and long-term inter- regional studies, that further assure the reliability of the interconnected bulk power system.

- ✓ Review event analyses of operational disturbances both internal and external to NPCC in order to identify any lessons to be learned and recommend the necessary follow-up, including the recommendation of remedial or mitigating actions.

- ✓ Approve those Guideline/White Paper Documents brought forth to the RCC by the Task Forces.

- ✓ Review and approve, prior to issuance, 2012 and 2013 NPCC Summer Reliability Assessment. ***April 2012/2013.***

NPCC, Inc.

Reliability Coordinating Committee
Work Plan for Calendar Year 2012-2013

- ✓ Review and approve, prior to issuance, the annual NPCC Long-Range Adequacy Overview. ***December 2012/2013.***

- ✓ Review prior to issuance, the 2012-2013 and 2013-2014 NPCC Winter Reliability Assessment(s). ***November 2012/2013.***

- ✓ Review and approve any new or modified Type-I & Type II Special Protection Systems presented in 2012-2013.

- ✓ Conduct Joint Task Force Chairs Conference Calls/Meetings on a regular basis.

- ✓ Develop the 2013-2014 and 2014-2015 RCC Work Plan. ***November 2012/2013.***

- ✓ Review and approve 2013-2014 and 2014-2015 Work Plans for the NPCC Task Forces. ***November 2012/2013.***

- ✓ Review and approve any special assessments required in 2012-2013 as described in the RCC Scope.

- ✓ Carry out additional responsibilities in 2012-2013 not mentioned above but contained in the RCC Scope, or as directed by the NPCC Board.

NPCC, Inc.

Reliability Coordinating Committee
Work Plan for Calendar Year 2012-2013

The following Reliability Coordinating Committee (RCC) activities planned for 2012 – 2013 are consistent with the NPCC 2012 Business Plan approved by the NPCC Board June 30, 2011 and the RCC Scope of activities approved by the NPCC BOD on February 3, 2009.

Core Reliability Criteria Functions

- ✓ Review and approve Comprehensive Area Transmission Reviews and Comprehensive Resource Adequacy Reviews brought forth before the RCC.

- ✓ Review and endorse new and revised Regional Reliability Directories and transmit a recommendation to the Full Members of NPCC for their final approval vote, in accordance with the NPCC Regional Reliability Directory Approval Process, and the NPCC Bylaws.

- ✓ As per the filed and approved "NPCC Regional Standards Development Procedure, oversee Task Force drafting and development of NPCC Regional Reliability Standards on the schedule set forth by the NPCC Regional Standards Committee and in accordance with the "NERC Reliability Standards Work Plan 2012 – 2013," as amended from time to time.

- ✓ Enhance the NPCC Regional Criteria Development process by encouraging and implementing procedures allowing for greater interregional interaction, communication and review, and by strengthening the design-based approach in regionally – specific criteria.

- ✓ Include any proposed revision of NPCC Criteria (as per NPCC Reliability Assessment Program (NRAP) schedule) during the development of the related NPCC Reliability Directories.

- ✓ Consider development of new NPCC regionally-specific, more stringent reliability criteria as part of the NPCC Reliability Directory process.

- ✓ Review NPCC Reliability Directories, procedures, guides, white papers, data, website(s) and databases to comply with NERC Reliability Standards and to promote reliability assurance in the NPCC Region.

- ✓ Review proposed NPCC Regional Standards, provide comments, during the period comments are being accepted, to the Regional Standards section of the NPCC Open Process for consideration by the respective NPCC Task Force

NPCC, Inc.

Reliability Coordinating Committee
Work Plan for Calendar Year 2012-2013

Drafting Team. Support the NPCC Regional Standards Committee as necessary in the identification of potential reliability related concerns and assist with the development and revision of Regional Standards, Variances, and/or Requests for Interpretations.

✓ Monitor developments at NERC for event related recommendations and incorporate into the NPCC Directories as necessary to meet the reliability objectives of Northeastern North America.

✓ Provide technical support to the NPCC Regional Compliance Committee as required in the review of NERC Standards, Compliance Application Notices "CAN"s, performing field tests and providing information for reports such as the NPCC's Cost Effective Analysis Procedure.

Provide technical support to the NPCC Regional Standards Committee's review of NERC Standards.

<u>On-going activities</u>

✓ Develop NPCC technical input and positions on NERC and FERC activities.

✓ Complete follow-up activities from the NPCC Blackout (2003) Study.

✓ Actively participate in the Eastern Interconnection Reliability Assessment Group (ERAG) activities.

✓ Actively participate in the established joint technical forum with Reliability *First* Corporation and the Midwest Reliability Organization to assure wide area, inter-regional coordination, by exchanging ideas and practices, including the identification of the need for appropriate near-term and long-term inter- regional studies, that further assure the reliability of the interconnected bulk power system.

✓ Review event analyses of operational disturbances both internal and external to NPCC in order to identify any lessons to be learned and recommend the necessary follow-up, including the recommendation of remedial or mitigating actions.

✓ Approve those Guideline/White Paper Documents brought forth to the RCC by the Task Forces.

NPCC, Inc.

Reliability Coordinating Committee
Work Plan for Calendar Year 2012-2013

- ✓ Review and approve, prior to issuance, 2012 and 2013 NPCC Summer Reliability Assessment. ***April*** *2012/**2013.***
- ✓ Review and approve, prior to issuance, the annual NPCC Long-Range Adequacy Overview. ***December 2012/2013.***
- ✓ Review prior to issuance, the 2012-2013 and 2013-2014 NPCC Winter Reliability Assessment(s). ***November*** *2012/**2013.***
- ✓ Review and approve any new or modified Type-I & Type II Special Protection Systems presented in 2012-2013.
- ✓ Conduct Joint Task Force Chairs Conference Calls/Meetings on a regular basis.
- ✓ Develop the 2013-2014 and 2014-2015 RCC Work Plan. ***November 2012/2013.***
- ✓ Review and approve 2013-2014 and 2014-2015 Work Plans for the NPCC Task Forces. ***November 2012****/2013.*
- ✓ Review and approve any special assessments required in 2012-2013 as described in the RCC Scope.
- ✓ Carry out additional responsibilities in 2012-2013 not mentioned above but contained in the RCC Scope, or as directed by the NPCC Board.

NPCC, Inc.

2011 Corporate Goal Attainment Report

With Summarized and Auditable Scoring

Gateway Goal

The stretch level for the budget administration gateway goal is projected to be met. While there remains the potential for the independent auditors to make reclassifications which could yield slightly different numeric results for 2011, the goal attainment level should not be affected. During 2011, NPCC experienced significant recruiting challenges pushing existing staff extensively with massive efforts and long work weeks. NPCC's referral award program continues to be an extremely cost effective tool for recruiting qualified individuals and NPCC avoided substantial recruiting firm fees that could have been incurred in association with attracting qualified employees for open positions. Amendments with regard to the Bylaws of NPCC and changes affecting the future governance structure were well communicated and received near unanimous support within the Membership. As a result of successful efforts, NPCC implemented a hybrid Board structure effective January 1, 2012. Negotiation resulting in significant savings associated with selection of an Executive Search firm to assist the Corporate Governance and Nominating Committee in its comprehensive efforts to identify, screen, interview and ultimately select qualified Independent Directors to populate the newly formed Independent voting sector were extremely fruitful.

The 2011 Regional Entity Division Year End Budget Report which is required by NERC in late January, 2012 will be distributed via e-mail along with the unaudited financial statements for December 31, 2011 for total NPCC (Regional Entity & Criteria Services Divisions) prior to the February 1, 2012 meeting of the Board. The financial statements will indicate that receipts were on target for 2011 and expenditures were within the stretch goal parameter approved by the Board and consistent with an organization capable of significantly enhancing reliability and with lean operations achieved through major reshuffling of priorities within the year 2011.

Based on the staff self-assessment that follows, NPCC's performance with regard to both Regional Entity and Criteria Services Divisions 2011 Corporate Goal Attainment presented in this report is estimated as being "*Exceeds Target*" with a composite score of 95**%**.

2011 NPCC Goal Metric Summary – Ratings and Scores

Goal	*Rating*	*Score*	*Weighting (%)*	*Weighted Score*
#1	Stretch	100	10	**10**
#2	Stretch	100	20	**20**
#3a.	Stretch	100	15	**15**
#3b.	Stretch	100	15	**15**
#4	Target	80	5	**4**
#5	Target	80	10	**8**
#6a	Stretch	100	15	**15**
#6b	Target	80	10	**8**
			100	***95***

Goals	Threshold	Target	Stretch	Weight
Goal #1. Executive and Administrative	Operate within 103% of the initial 2011 Budget as well as applications approved by the Board from operating cash reserves. Approval by the Board and submission to the NPCC Membership of Amended NPCC Bylaws and Governance Change no later than [May 1]. Incorporation by NERC of at least 60% of NPCC Board policy input.	Operate within the initial 2011 Budget as well as applications approved by the Board from operating cash reserves. Approval by the NPCC Members of Amended NPCC Bylaws and Governance Change for submission to NERC Board of Trustees no later than [September 1]. Incorporation by NERC of at least 75% of NPCC Board policy input.	As an overall efficiency goal, operate within 95% of the initial 2011 Budget as well as applications approved by the Board from operating cash reserves. Approval by NERC and regulatory authorities of Amended NPCC Bylaws, and Governance Change for implementation effective January 1, 2012. Incorporation by NERC of at least 90% of NPCC Board policy input.	10

Goal #1 Executive and Administrative

Assessment of Goal Attainment: The Stretch attainment level for Goal #1 was achieved. NPCC's unaudited statement of activities for the period ending December 31, 2011 for the Regional Entity and Criteria Services divisions reflect expenditures totaling approximately 88% of budget. A revised Regional Delegation Agreement which incorporates the Amended and Restated NPCC Bylaws received FERC's unqualified approval for implementation, effective January 1, 2012. During 2011, NERC incorporated almost all of NPCC's submitted Board policy input in some 12 areas, with the NPCC recommendation for regulatory closure of mitigated possible violations submitted through the "Find, Fix and Track" process still under consideration by NERC.

Supporting Materials and Background

NPCC's unaudited statement of activities for the period ending December 31, 2011 for the Regional Entity and Criteria Services divisions reflect expenditures totaling approximately $12,137,105 as compared to a total 2011 budget of $13,812,600 or roughly 88% of budget. A Regional Entity division budget and cash reserve requirement totaling $13,081,110 was satisfied by NERC assessments to NPCC Load Serving Entity designees in a total amount of $12,652,610 for budget year 2011. The 2011 assessment was reduced by the application of penalty sanctions of $308,500 received through June 30, 2010 and 2011 stakeholder workshop fees ($120,000). The Criteria Services division budget totaling $1,020,471 was satisfied through NPCC direct assessments to its ISOs and Balancing Authority Areas. The 2011 assessment was reduced by the application of cash reserves totaling $664,691 for a total funding requirement of $349,600 for Criteria Services.

During 2011, NPCC submitted Board policy input in some 12 areas involving: a reduction in NERC's proposed staff additions and budget for 2012; initiation of selective field trails for proposed data intensive NERC metrics; a more transparent Compliance Application Notice development process; a phased approach to implementation of new Cyber standards; and, numerous NERC Rules of Procedure changes supportive of effective and efficient assurance of Northeast reliability.

With respect to overall ERO Enterprise strategy, NPCC successfully introduced explicit cost assessment into standards development and Adequate Level of Reliability considerations, and developed an industry-leading Cost Effectiveness Analysis Procedure. The NPCC Board's input shaped the ERO's top priorities for 2012 and focused future compliance efforts on risk-informed activities. NPCC also focused NERC compliance enforcement initiatives on providing efficiencies in Regional Entity and registered entity compliance efforts, and strived to obtain regulatory closure to mitigated possible violations.

Regarding the definition of the Bulk Electric System, NPCC's policy input helped establish a technical based exception process with clear criteria for excluded distribution facilities, protected Canadian authorities for alternative processes, and successfully advocated for an adequate transition period.

NPCC's input on Events Analysis improvements shaped the industry-based process and NPCC staff led the ERO's implementation. NPCC policy recommendations also enhanced industry-wide learning opportunities in a revised NERC Alert process and successfully streamlined the Alert response requirements.

Working with NERC, NPCC staff developed a revised Regional Delegation Agreement which incorporated the Amended and Restated NPCC Bylaws and the Board's endorsed responsibility for NPCC to act as the Compliance Enforcement Authority for the registered entity functions performed by the Western Electricity Coordinating Council. Following the NERC Board of Trustees unanimous approval, NPCC conducted significant outreach efforts with FERC staff and ultimately obtained FERC's unqualified approval of implementation of the revised RDA effective January 1, 2012.

NPCC organized a meetings of the NPCC Governmental/Regulatory Affairs Advisory Group in conjunction with the NPCC 2011 General Meeting, that provided an opportunity to review NPCC reliability interests with Federal/State/Provincial regulatory and/or governmental authorities, and provide a forum for industry and governmental/regulatory representatives to exchange information and discuss the development of recommendations to the NPCC Board. A FERC representative discussed the recent Commission Order 1000, NERC presented the results of their recent scenario assessment of anticipated reliability impacts from proposed EPA regulations, and ISO-NE and NERC representatives provided an update on anticipated upcoming Gas/Electric Interdependency analysis. In addition, a status of the Eastern Interconnection Planning Collaborative activates was provided.

Additional 2011 NPCC Accomplishments

(Opportunities that emerged after the NPCC Goal Metrics or Components were approved)

In the NPCC IT area in 2011 there were a number of notable accomplishments:

- Implementation of a credit card billing system was rolled out for the December Compliance and Standards Workshop. Previously, participants made payments via check.
- Initiated the development of the NPCC Purchase Order program to replace several manual processes and improve efficiency, accuracy and consistency for many day to day repetitive activities. Areas enhanced include: inventory review, order placement and approvals, receipts, context sensitive vendor and service lists and codes to maintain complete order history, payments, pricing and usage volumes. Compliance staff worked collaboratively with Registration staff, to extend the design of the electronic application

to encompass payroll and financial information. This tool has been implemented and will greatly enhance preparations for financial audits.

- A "Wiki" site was added to the Compliance section to promote the sharing of issues and information.
- An Event Capture Scheme/database was developed for the Event Analysis program
- Secure file transfer system was set up for the secure transfer of CEII information
- NPCC Chaired the Steering Group for IT at NERC, ITSG which will help develop and define NERC's IT strategy and provide an avenue into NERC's IT decisions for our members.
- NPCC designed and put into production, a new website with improved user interface and functionality
- NPCC staff provided a rigorous review of the NPCC's Disaster Recovery/Business Continuity Plan. Detailed comments were provided to the NPCC IT group so that they could enhance the robustness and utility of the Plan to better ensure its implementation during a disaster. Changes have been incorporated into the plan to reflect lessons learned during actual emergencies.

Goals	Threshold	Target	Stretch	Weight
Goal #2. Reliability Standards Program	NERC Support Activity Actively participate in the version 5 Cyber Security Standards development and effectively promote the Northeast's stakeholders comments. NPCC Regional Standard Activity Develop new Regional Standards web pages – by 12/11. NPCC Criteria Activity Develop NPCC Glossary of Terms based on Phase 1 of the Directory Project for RSC approval – by 12/11.	Attainment of Threshold Goal and: NERC Support Activity Develop a "triage" process to efficiently and effectively utilize NPCC's internal and external resources to review standards – by 12/11. NPCC Regional Standards Activity Develop and post 3rd Regional Standard and implement a Standards Quality Review process within NPCC for regional standards – by 12/11. NPCC Criteria Activity Achieve RSC endorsement of an NPCC Directory Development Manual – by 12/11.	Attainment of Target Goal and: NERC Support Activity Assist in the development of enhanced interpretation procedures and prioritization processes for ERO standards – by 12/11. NPCC Regional Standard Activity Post enhanced NPCC Regional Standards Process Manual incorporating new NERC and FERC processes suitable for posting. NPCC Criteria Activity Complete set of Phase 2 NPCC Directory Project initial translations and ballot two directories – by 12/11.	20

Goal #2 Reliability Standards Program

Assessment of Goal Attainment: The Stretch attainment level for Goal #2 was achieved (100% of Stretch level achieved). In addition, there was a furtherance of the deliverables beyond the stated goals. All the objectives identified in the Threshold and Target categories were fully achieved by, and in most cases well prior to, the dates indicated. During 2011, NPCC staff participated on the Standards Committee Process Subcommittee in the development and enhancement of a NERC standards project prioritization tool, and a "Rapid Revision" process to address the "repair" of standards issues identified through the interpretation and compliance processes. NPCC also participated in commenting on the NERC Compliance Application Notice

process (CANs) which is another enhancement of the "suite" of NERC tools to provide clarity. In the last Quarter of 2011 the NPCC RSC proposed changes to the NPCC Regional Reliability Standards Development Procedure to reflect changes within NERC and FERC and approved posting of the enhanced standards development document in December for a 45 posting period for comments. In December, initial draft translations of all the directories was completed and two NPCC Reliability Directories, #9 and #10 Generator Verification Directories, which reflected Phase II of the Directory Project efforts were approved by the NPCC Full Member Representatives in December of 2011.

Supporting Materials and Background

The 2011 NPCC BOD approved Goals for the standards program area were based on three categories of activities as follows: support of NERC activities, NPCC Regional Standards Activities, and NPCC Criteria Related Activities.

NERC Support Activities

NPCC was proactively engaged in a number of NERC standards, initiatives and process developments. Included in these activities, is the continuing active involvement of Staff and NPCC Task Force on Infrastructure Security and Technology (TFIST) members in the development of Version 5 CIP (Cyber Security) standards. NPCC conducted numerous meetings of the NPCC Regional Standards Committee (RSC) and TFIST on the Version 5 proposal, participated in several webinars and made presentations of the materials to the NPCC Members at Compliance Workshops. NPCC staff also participated in numerous standard drafting team (SDT) meetings and provided the Northeast perspective and ensured that the comments submitted to the team were understood and addressed. The latest draft version of the standard, which incorporates significant Northeast input, still requires additional work to make it acceptable and is before the industry in the initial balloting/commenting process.

The RSC developed a Triage process to more efficiently and effectively utilize subject matter expertise from the Northeast to improve the quality of NERC's standards and provide NPCC Member input to the standards' development. NPCC staff participated on the Standards Committee Process Subcommittee "SCPS" in the development of the NERC project prioritization tool. The SCPS also developed a "Rapid Revision" process which is being implemented to address the "repair" of standards issues identified through the interpretation and compliance processes. The SCPS also has a subgroup, led by NPCC, which is currently engaged in developing a system to insure that drafting team members are properly qualified and revising the SDT nomination processes. The RSC has also provided input to the Compliance Application Notice (CAN) Process which is used as an alternative for the industry to more quickly clarify compliance application issues, which previously could only be addressed through the formal interpretation process.

Additionally, the RSC reviewed more than 13 individual projects and sent out ballot recommendations and/or lists of issues and concerns to the ballot body participants in NPCC. The RSC also commented on more than 45 individual standard projects, other NERC documents, and 24 CANs, while expressing the Northeast perspective of NPCC's Members on the posted materials. The NPCC RSC also tracks SDT membership to ensure that all NERC standard drafting activities are staffed with either NPCC Member participants or NPCC Staff to ensure the reliability objectives of the Northeast are represented. NPCC staff has also filled critical gaps when necessary on NERC Committees, Subcommittees, Task Forces and Working Groups to ensure representation is maintained and the Northeast's perspectives are promoted. The NPCC Standards program area has also provided support to the following groups at NERC: the Standards Committee, the SCPS, the Functional Model Working Group, the Reliability Metrics

Working Group, the System Protection and Control Subcommittee, and the NERC Regional Standards Group (RSG). Significantly, the RSG is currently developing a number of initiatives that will focus on consistency between regions, providing clarity to the variance and Regional standard processes and the criteria for initiating them. The RSG has also been actively engaged in reviewing the NERC Evaluation Procedure for Regional Standards.

NPCC Standards Staff, taking into consideration the concerns of the RSC, participated in the NERC Standards Committee Process Subcommittee (SCPS). The SCPS developed enhancements to the Project Prioritization Tool and used these enhancements to develop the draft of the 2012-2014 Standards Development Workplan. The enhancements included consideration of costs and regulatory deadlines. The enhancements also assist with the division of the NERC projects into three prioritizations based on: reliability, time and practicality. The SCPS also provided input into the various interpretation initiatives, the Compliance Application Notice process, as well as the rapid revision procedure for standards. The rapid revision procedure will provide a procedure to expedite revisions to standards that may be ambiguous or have vague requirements. In addition NPCC staff developed a revised set of criteria for NERC standard drafting team selection to ensure the proper expertise level of potential team members.

NPCC Standards and Legal staff, also participated in "Quality Review (QR) Training" at NERC and is now assisting the ERO with reviewing standards for the necessary level of quality prior to postings. These QRs focus on ensuring that the standards have the necessary technical writing clarity, in addition to adequate compliance and legal review along with proper formatting and style.

NPCC staff also made classroom presentations at the NPCC's Fall Compliance Workshop on the Disturbance Monitoring and Automatic Underfrequency Load Shedding regional standards.

NPCC Regional Standard Activities

2011 was indeed a landmark year for NPCC in the area of Regional Standards. The NPCC Board of Directors approved the first NPCC Regional standard, (Disturbance Monitoring "DM", PRC-002-NPCC-01), and it was subsequently approved by the NERC Board of Trustees and filed with the Federal Energy Regulatory Commission "FERC". NPCC staff worked with NERC legal in excess of 4 months to produce the filing and in addition conducted two teleconferences with the FERC Office of Enforcement and Office of Electric Reliability to review the intent of the standard and to answer commission staff questions subsequent to the NERC filing. PRC-002-NPCC-01 was approved by the FERC on October 20, 2011. Importantly, FERC issued no Directives to modify the standard. This is a testament to the high quality of the standard and the effort by the NPCC SDT, members, and staff. Also the Members of NPCC recently approved the PRC-006-NPCC-01 Automatic Underfrequency Load Shedding Program – a Regional standard developed from Directory No. 12.

In addition, the RSC developed and piloted an NPCC Cost Effectiveness Analysis Procedure "CEAP". This is a two phase analysis that performs a high level Cost Benefit study upon the initial consideration to develop a Regional reliability standard. The RSC will use this Phase 1 of the CEAP to determine if a standard is of sufficient reliability benefit, given the potential costs, to justify moving it forward to develop. Once the draft standard has been developed the second phase of the procedure is to determine if there are any more cost efficient ways of achieving the reliability objective of the standard and if the standard, in the opinion of industry, is cost effective in achieving that objective.

During the past year staff has made presentations to the Board, RCC, RSC, CC and the North American Generator Forum in the areas of Cost Effectiveness and Compliance support. The NPCC Cost Effectiveness Analysis Procedure was posted and shared at NERC as a foundation document on which to build a similar initiative for ERO standards.

In August of 2011, a new NPCC website with increased functionality was put into production. The new website provides more transparency, is easier to navigate and incorporates "progress" bars for the individual standards to allow the stakeholders to immediately identify where in the process the individual standards may currently exist.

NPCC began work on the third NPCC Regional standard, Reserve Sharing BAL-002-NPCC-01. The standard was drafted and posted on the NPCC website for an initial comment period. The RCC assigned the drafting of the standard to the Task Force on Coordination of Operations. Additionally, industry participants were solicited for regional SDT appointment.

During 2011 NPCC also worked with the RSG to review the consistency issues between the regions and developed a first draft of the revised NPCC Regional Standards Development Process. The standard has been posted on the NPCC website for comment and also submitted to NERC for posting on their website to ensure "interregional" comments are addressed. The proposed revisions to the process will implement proposed efficiencies, address gaps, introduce new attributes to promote quality and increase flexibility of NPCC's standards development.

NPCC Criteria Related Activities

A NPCC Glossary of Terms developed from the Phase 1 Directory translation project was approved by the RSC during 2011. The new Glossary replaced Document A07 and is posted in the Directory section of the NPCC website. The Glossary contains references to where the NPCC terms are used and also whether the terms may differ from NERC Glossary Terms so that the Task Forces of NPCC can review the differences and move towards eliminating instances where the definitions differ by either adopting the NERC term, or initiating the NERC Standards Development Process to change the NPCC defined term to the NERC term.

In October of 2011 the RSC also approved a new Directory Development Manual. This Manual was developed to assist the NPCC membership in understanding how to coordinate revisions to a reliability Directory, how to develop a new one, seek interpretation to Criteria in the Directory and revise the NPCC Glossary. The Manual is posted on the NPCC website in the Directory section for member use and will provide some insight on how to coordinate reviews of Directory's when revisions to sections of a Directory are necessary by multiple Task Forces.

All the initial Phase 2 drafts of existing Directories have been completed by NPCC staff and are available for Task Force use as a starting point for their revisions and deliberations. The TFCO working with NPCC Standard staff completed the development of the first Phase 2 Directory translations when Directory No. 9 and No. 10 for Generator Verification were approved by the TFCO and the Reliability Coordinating Committee "RCC" in November 2011. The Directories were balloted and approved by the Full NPCC Membership in December 2011.

The Phase 2 reformatting of Directory No. 1 Design and Operation of the BPS and a new Directory No. 6 outlining the process for Reserve Sharing were both drafted by NPCC Task Forces under RSC oversight and are moving through the review process.

Goals	Threshold	Target	Stretch	Weight
Goal #3a. Compliance Monitoring and Enforcement Program (CMEP) - Internal Quality Enhancement Program (QEP)	Distribute a NPCC Culture of Compliance Survey to selected registered entities and evaluate responses submitted and revise Survey as necessary – by 4/11. Demonstrate a 5 % efficiency gain in the processing of violations that result in either a signed settlement agreement or a Notice of confirmed violation – by 12/11	Attainment of Threshold Goal and: Distribute enhanced Culture of Compliance Survey to all NPCC registered entities; evaluate 75% of registered entity responses – by 12/11. Demonstrate a 10% efficiency gain in the processing of violations that result in either a signed settlement agreement or a Notice of confirmed violation – by 12/11	Attainment of Target Goal and: Evaluate 100% of registered entity responses and develop and disseminate corrective action programs to provide assistance to 50% of the lesser performing (lower graded) entities – by 12/11. Demonstrate a 15 % efficiency gain in the processing of violations that result in either a signed settlement agreement or a Notice of confirmed violation – by 12/11	15

Goal #3a Compliance Registration and Enforcement

Assessment of Goal Attainment: The Stretch attainment level for Goal #3a was achieved (100% of Stretch level achieved). Goal #3a consisted of two parts: 1) the Culture of Compliance Survey Initiative and 2) the Improving the Efficiency of Violation Processing Initiative. NPCC staff developed and distributed a total of 165 NPCC Culture of Compliance Surveys, covering all 287 NPCC registered entities. The staff evaluated 100% of the 146 survey responses received. In 2011, the enforcement staff, despite an increase in personnel of 11%, had a workload increase of 26%. In 2010 there were 72 violations closed that consisted of dismissals, signed settlement agreements or issuances of NOCV's. In 2011, through December 20, there were 130 violations closed via the same activities. Taking into consideration the increase in enforcement staff and the increase in number of violations closed, a violation processing efficiency increase of 61% over 2010 was realized during 2011, by the NPCC enforcement staff.

Supporting Materials and Background

The Culture of Compliance Survey evaluations consisted of reviewing the material sent by each registered entity, conducting one-on-one assessment phone calls with each survey submitter, rating each registered entity, and identifying Examples of Excellence and Best Practices. The survey initiative is documented in the "Report on 2011 NPCC Culture of Compliance Survey Initiative", which is posted on the NPCC Website and available on the CDAA portal. The report includes a compilation of the Examples of Excellence and the Best Practices identified which present potential mechanisms or corrective action programs for registered entities to consider when reviewing or enhancing their internal compliance programs.

A detailed presentation, on the 2011 NPCC Culture of Compliance Survey Initiative, was made at the 2011 Fall NPCC Compliance and Standards Workshop held on December 14 -16, 2011 and attended by over 200 people. A follow-up webinar will be held in January 2012 with all NPCC registered entities to discuss the report in detail.

NPCC Culture of Compliance Survey Initiative and Development

NPCC defines a Culture of Compliance as an environment in which a registered entity demonstrates continuing awareness and commitment to meeting its obligations as they relate to the NERC Reliability Standards. A sound and effective Culture of Compliance is a critical component in assuring the reliability of the Bulk Electric System.

NPCC viewed this initiative as a tool for improvement, to be used by the registered entity to ultimately improve the reliability of the Bulk Electric System. The goals of the initiative were for:

- NPCC to gain an overall perspective of the culture in the region;
- each registered entity to identify opportunities for growth or confirm that processes were already in place; and,
- NPCC to identify and share, with all registered entities, Examples of Excellence and Best Practices.

NPCC developed a survey to evaluate a registered entity's Culture of Compliance based on the following FERC policy statements: the October 2005 Policy Statement on Enforcement (a.k.a. "13 Questions"); the May 2008 Revised Policy Statement on Enforcement; the October 2008 Policy Statement on Compliance; and, the September 2010 Revised Policy Statement of Penalty Guidelines.

Each of the FERC policy statements highlighted attributes and/or characteristics that the Commission believed a registered entity's internal compliance program should contain to ensure an effective Culture of Compliance and therefore create an environment conducive to a reliable Bulk Electric System.

Implementation of Initiative

In January 2011, an initial Culture of Compliance Survey was approved by NPCC Compliance Committee and distributed, as part of initial trial test, in February, 2011. The initial trial test (Phase 1) was conducted with a select number of registered entities (58), representing a cross section of entity types (functions, size, etc.). A webinar was held with trial test participants in advance of the submittal of survey responses to clarify the purpose of the survey and answer questions. A post submittal webinar was also held with trial test participants to allow them to discuss the survey process and provide any comments on either possible process changes and/or survey changes to NPCC Staff.

A revised and enhanced survey was then developed and presented to NPCC Compliance Committee for review and approval. The Compliance Committee approved the enhanced survey at its June, 2011 meeting. The enhanced survey was sent to all remaining NPCC registered entities.

Evaluation of Survey Responses

NPCC used the generic categories of the functional model to determine whether the minimum requirements of a culture of compliance existed. The categories for relative comparison used by NPCC Staff were RC/BA, TO/TOP, GO/GOP, DP/LSE, and PSE. These categories are characterized by the common content, common themes, and common depth of data provided by an entity in that particular category.

NPCC Staff performed the subjective analysis of each survey response and placed each survey into one of three measurement buckets:

- "Green" – The survey response indicates that the entity meets or exceeds all minimum characteristics of a favorable Culture of Compliance;
- "Yellow" – The survey response indicates that the entity does not meet all minimum characteristics of a favorable Culture of Compliance; and,
- "Red" – The survey response indicates that the entity meets few or no minimum characteristics of a favorable Culture of Compliance.

The overwhelming majority of survey responses had a "Green" culture and an inherent fundamental understanding of their compliance obligations. A minority of responses were assessed as a "Yellow". In each of those cases, a feedback phone call was used to verify and pursue additional questions to assist the entity in attaining a higher measurement bucket. There were no survey responses that were assessed as a "Red" culture.

NPCC staff completed its evaluation of all surveys received at the end of December 2011. In addition, NPCC Staff put forth tremendous effort and time to coordinate a feedback phone call with every Registered Entity that provided a survey response. This resulted in 146 phone calls that encompassed 265 Registered Entities being made over four months. For the overwhelming majority of responses, the feedback calls served as an acknowledgement to the compliance personnel at each entity that NPCC staff viewed the culture exhibited in their survey response in a positive light. As stated earlier, a minority of the calls served to first clarify the contents of the response followed by the acknowledgement that NPCC staff viewed the culture exhibited in a positive light.

The "Report on 2011 NPCC Culture of Compliance Survey Initiative" will be sent to the Primary Compliance Contact at each of the 22 Registered Entities that did not provide a survey response. This will ensure that those entities have the opportunity to review the Examples of Excellence and Best Practices that could potentially enhance their compliance programs.

Dissemination of NPCC's Initiative to NERC, Other Regional Entities and Trade Associations

The activities undertaken by NPCC related to the Culture of Compliance Survey have been shared with various sectors of the industry which include: the NERC Board of Trustees Compliance Committee, the Electric Reliability Organization Compliance and Enforcement Management Group (ECEMG), the North American Generator Forum (NAGF), the North American Transmission Forum (NATF), and the Large Public Power Council (LPPC). In addition, the survey is being considered as the model for the culture of compliance component of NERC's forthcoming Entity Assessment efforts.

In 2011 NPCC demonstrated a significant increase in the efficiency of processing violations that it has identified during its implementation of the Compliance Monitoring and Enforcement Program (CMEP). The metric used to demonstrate this increase in violation processing efficiency was the percentage increase in the number of violations closed in 2011 per enforcement staff member versus the number of violations closed in 2010. NPCC defines a violation as closed when the NPCC Enforcement Staff has obtained a signed Settlement Agreement; issued a Notice of Confirmed Violation (NOCV) or dismissed a violation.

In 2011, the enforcement staff, despite increased in personnel of 11% and had a workload increase of 26%. In 2010 there were 72 violations closed that consisted of dismissals, signed settlement agreements or issuances of NOCV's. In 2011, through December 20, there were 130 violations closed via the same activities. Taking into consideration the increase in enforcement

staff and the increase in number of violations closed, a violation processing efficiency increase of 61% over 2010 was realized during 2011, by the NPCC enforcement staff.

Efficiency Improvement Factors

There are a number of factors that have contributed to this increase in violation processing efficiency. These factors include:

- The implementation, by NPCC, of the NERC-wide Administrative Citation Process (ACP) in the overall enforcement process. This process was introduced at the end of 2010 and fully implemented by NPCC in January 2011. The ACP process was introduced to streamline the enforcement process by expediting the closing of administrative type violations which had a minimal to moderate impact to the reliability of the Bulk Electric System (BES). NPCC was a leader in the use of the ACP process from its onset and provided a number of candidates for the initial and subsequent ACP filings. NPCC also promoted the use of this process at various NERC groups.
- The implementation, by NPCC, of the Find, Fix, and Track Process (FFT). This initiative was introduced in August 2011 and implemented in September, 2011 and augmented the ACP process to further streamline the enforcement process. The FFT process focuses on violations where the entity has already implemented corrective actions and would only require the submittal of mitigating activities and a certification to prove compliance. In addition these violations are for those that pose a lesser risk (minimal to moderate) to the reliability of the BES. As with the ACP process NPCC was very supportive of the FFT process and promoted its use among other Regional Entities and NERC. The ACP and FFT processes, by focusing on violations that have less of an impact on the reliability of the BES, has allowed the NPCC Enforcement Staff to focus greater resources on the processing of more serious violations that have higher impact to the BES.
- The development of new enforcement processing tools and the enhancement of existing enforcement processing tools. These included the :
    - ✓ Introduction of the Compliance Information Tracking System (CITS). This new software enhancement was implemented to electronically track all violations submitted by the registered entities or found by NPCC. This enhancement allows for all information to reside in one database and greatly improves the review process of violations, the electronic tracking status of mitigation plans and provides consistency in the reporting of violation processing data among the registered entities, NERC and other Regional Entities. CITS also replaced manual workbooks, which were cumbersome and inefficient for processing the data, with an electronic web service that allows for direct data transfer to NERC. NPCC Staff played an integral role in the integration of CITS both internally at NPCC, and externally with NERC. The deployment of a letter generator, a future enhancement to CITS that is currently under development, will add functionality that will allow the NPCC Enforcement Staff to generate the required letters for processing violations under the CMEP rules. This enhancement will eliminate duplicative work and provide uniformity in documentation wording. In addition, the CITS Letter Generator Tool will have a reporting mechanism that will notify Enforcement staff on the status of outstanding letters that are required to be sent.
    - ✓ Enhancements to the NPCC registered entity portal (known as CDAA). The addition and enhancements of new forms have been implemented into the enforcement process. These upgrades have automated the process and resulted in the elimination of the manual processes that existed and were related to the development of self-report forms; mitigation plan forms; milestone update forms;

extension forms; Certification of Completion forms; and electronic authorized signature required on applicable forms.

- ✓ The development of the Violations Reporting System (VRS) that provides a tool/mechanism for keeping track of all NERC reliability standard violations being processed by NPCC enforcement staff. VRS enables NPCC enforcement staff to store significant amounts of violation processing data and use this data to analyze enforcement processing activities. In addition it automatically tracks the progress of violation processing and provides statistics about violations within NPCC. These statistics include but not limited to the following: Notice of Possible Violations (NOPV) Reports/Statistics; Yearly Discovery Methods; Notice of Alleged Violations and Penalty Sanctions (NAVAPS) Reports/Statistics; Settlement Reports/Statistics; Dismissed Violations Reports/Statistics; Notice of Confirmed Violations (NOCV) Reports/Statistics; Closed Violations Reports/Statistics; Carried-Over Violations Reports/Statistics; Yearly Violations Processing Duration Report/Statistics. VRS allows the NPCC staff to significantly improve its assessment of the processing of violations, thereby being able to make informed decisions and continue to improve the efficiency of processing of violations.
- ✓ Enhancements to existing registration processes, particularly those related to the selling, transferring, and/or merging of existing assets. These activities in the past have caused significant delays in the processing of outstanding violations as the changing asset ownership issues are resolved.

Goals	Threshold	Target	Stretch	Weight
Goal #3b. Compliance Audits and Investigations	Develop a corroborating evidence document library of registered entity supporting material for TFE justifications – by 6/11 Review and acknowledge audit feedback from registered entities within 60 days of receipt.	Attainment of Threshold Goal and: Make the TFE library available and usable by NPCC registered entities – by 9/11. Dismiss or implement feedback suggestions from registered entities within 120 days of receipt.	Promote NPCC TFE library to NERC and other Regional Entities to drive consistency in TFE processing – by 12/11. Develop a database of implemented feedback items and disseminate to all registered entities – by 12/11.	15

Goal #3b Compliance Audits and Investigations

Assessment of Goal Attainment: The Stretch attainment level for Goal #3b was achieved (100% of Stretch level achieved). NPCC developed a corroborating evidence document library for use in supporting TFE requests. This library is a "living" repository of supporting documents that is added to as more documentation becomes available. These documents enable expedited review of TFE's by referencing the known device and checking the corroborating documentation as justification. Prior to the library, each entity would have to obtain the information on a case-by-case basis. Also, database of responses to the implemented feedback items form audits has been developed to document and disseminate the suggestions and applicable resolutions to the registered entities via the NPCC compliance website. The results of 2011 Audit Feedback are posted on the NPCC public website.

Supporting Materials and Background

The structure of the TFE library was finalized and populated with documents for use by NPCC registered entities as early as February 2011, and finalized by April 2011 (before the Threshold date of 6/11). The TFE library is needed for instances where a known problem exists with certain equipment and the referenced TFE. For example, the Schweitzer Engineering Laboratories, Inc. process for mitigating malware risk to embedded devices, details Systems Security Management and outlines requirements for Malicious Software Prevention under CIP-007-1. Availability of the TFE library for use by NPCC entities has been announced as early as the NPCC 2011 Spring Compliance Workshop (before the Target Date of 9/11) and throughout the entire year via posting on NPCC's website and again at the NPCC Fall Compliance Workshop. NPCC has promoted the use of the TFE library to NERC and the other regions at the regional quarterly working group meetings held in April, July and December 2011 (before the Stretch date of 12/11). NERC has accepted the NPCC initiative and has encouraged the other Regional Entities to produce the same.

Enhance TFE Review Process

In addition to the corroborating evidence library, NPCC Compliance staff has developed consistent, effective and efficient processes to implement the review of TFEs. NPCC works with NERC and the other Regional Entities to document these processes and organize and promote their use via quarterly meetings.

NPCC has developed training presentations that have been presented at the NPCC Spring and Fall 2011 Compliance Workshops. New TFE processes and procedures are communicated via announcements and postings on the NPCC CDAA website.

NPCC's TFE Team has been instrumental in suggesting and initiating changes to the TFE process to make it more efficient and streamlined, thus reducing the impact on available resources.

Process Improvements by Incorporating Feedback from Compliance Audits

During audit exit briefings, NPCC solicits feedback from the audited entity via completion of the NERC Audit Feedback form. NPCC tracks, reviews and acknowledges feedback forms from each audited entity within 60 days of receipt. If a feedback form was not provided to NPCC in a timely manner, NPCC contacted the entity to remind them to complete the form and submit it. NPCC developed a tabulation and grading system to evaluate the audited entity responses for all the questions on the NERC feedback form. NPCC has a success rate of receiving nearly 100% of the feedback forms for their audits which is higher than other Regional Entities. All comments are reviewed, and any negative comments are looked upon as opportunities for improvement. Average score on seven of the nine questions was 9+ on a scale of 0-10 with 10 being the highest. Entity feedback has been very positive. The average score on two of the nine questions were lower for the following reasons. One question regarding "impact to work" received the same negative responses from several audited entities that were part of the same parent company, and from smaller entities. The second question regarding "suggestions from audits" is being further investigated to determine whether the audited entity's compliance program warranted any suggestions. Some of the low scoring concerns NERC mandated process factors that NPCC cannot change. All comments, including negative or non-implementable suggestions, have been discussed with the submitting entity within 120 days of their receipt.

NERC and FERC have observed several NPCC on-site audits and provided feedback leading to improvements in the NPCC audit process in the areas of interviewing, CEII data handling , rigor

in data requests and evidence tracking sheet security, audit team caucusing and end-of-day wrap-up with entity. Improvements to NPCC audit process are continually being made and suggestions are addressed at bi-monthly Auditor meetings. A database of responses to the implemented feedback items has been developed to document and disseminate the suggestions and applicable resolutions to the registered entities via the NPCC compliance website. The results of 2011 Audit Feedback are posted on the NPCC public website and are updated as more feedback is received.

Prepare a new NPCC Compliance Procedure for Mis-operation Reporting

NPCC staff took an active role in the development and implementation of a process and commensurate reporting templates, to address Protection System Mis-operations. This was the NERC President's "Top Priority Issue for Bulk Power System Reliability" in 2011. The process leveraged NPCC resources and actions to support the ERO-RAPA ALR4-1 metric, PRC-003 & PRC-004 compliance and TADS update. NPCC Compliance staff met with RAPA staff to develop a multi-purpose entity guidance document describing the bases, stakeholders, forms, actions, schedules, submittal process, and relationship between mis-operation quarterly reporting and compliance.

The new non-binding guidance document provides an overview of all the actions related to Protection System Mis-operation Reporting and the various stakeholders (entity and NPCC) that affect, and are affected by, mis-operations. The guide is a comprehensive and instructional document for applicable registered entities in the logistics, forms, deadlines, scope and processes for Mis-operation Reporting form to support the entities' required actions to meet multiple NERC requirements - Compliance, NERC metrics (ERO-RAPA) and NERC trending (TADS). The process was presented at the NPCC 2011 Spring Compliance Workshop. The guide, its references, blank reporting templates, and samples were posted on the NPCC public website in June 2011 and are provided as links in the NPCC quarterly reminder to the entities.

NPCC will also ensure all registered entities are using the mis-operation tracking process to provide a self check when Self Certifying compliance for the reporting period. This suggestion has been provided in the non-binding guide and in the quarterly reminder to the registered entities when the Mis-operation Reporting Template is due.

Coordination among Situation Awareness, Events Analysis and Compliance

In conjunction with the development of NERC's continent-wide Event Analysis Process (EAP), NPCC developed a Workflow Plan to coordinate the NPCC's Situational Awareness (SA), Event Analysis (EA) and Compliance Investigations and Enforcement Groups' efforts to create a more effective and efficient method for reviewing events. To this end, NPCC Compliance Investigation has authored a Compliance Instruction document CI-16 "Conducting NERC ERO Event Analysis Process" which specifies the roles and responsibilities of NPCC's SA, EA and Compliance Staff members for implementing the EAP within the NPCC region.

NPCC, together with SERC, has developed an Event Capture System application to track events occurring within the NPCC region. This application enables the tracking of the event from reporting inception through interim stages (event analysis/lessons learned/corrective actions) and finally compliance closure or handoff to Compliance Investigation and/or Enforcement. This application has been implemented during the Event Analysis Process phase II field trial. With NPCC's collaboration, SERC has enhanced their application and supports NPCC's suggestion to NERC to adopt the NPCC/SERC "best practice" as the model for the other Regional Entities.

Secure Data Submittals

To assure confidentiality of submitted data for the various components of the compliance program, registered entities are required to use the NPCC secure FTP site. To increase efficiency of the current process, NPCC implemented a clientless FTP solution. The new clientless solution has been well received by NPCC registered entities for several reasons such as no longer needing to install an FTP client on the entity computers and no longer having to open ports on the entity firewalls to permit outbound FTP traffic.

Other Audit and Investigations Group Accomplishments

Internal improvements and processes:

- Initiated reviews and updates of six (6) existing Compliance Procedures (CPs), and two (2) Compliance Instructions (CIs). Created one (1) new CP for Technical Feasibility Exception (TFEs). Revisions were made to align with Compliance Monitoring Enforcement Program (CMEP), NERC Rules of Procedures (ROP), NERC Compliance Directives and Bulletins. CPs and CIs are applicable to Operations & Planning (O&P) audits (44 off-site and 5 on-site), and CIP audits (2 off-site and 11 on-site) scheduled for 2012, Self Certifications, Self Reports, Spot Checks, TFEs, Events Analysis, and Compliance Investigations. The revised CPs have been posted on NPCC's public Compliance website.
- The NERC Event Analysis Process (EAP) Phase II program only requires compliance self assessments for Category 2 and higher events (Category 1 being "Lower significance" and Category 5 being "High significance"). NPCC has successfully encouraged its registered entities to conduct self assessments or standards reviews for all existing 53 qualifying events (Category 1 and up) as well as future events as a demonstration of a strong culture of Reliability and Compliance. All qualifying events were reviewed to determine an added benefit in the production of valuable lessons learned for the industry which may not have occurred had a formal compliance investigation been required.
- NPCC has championed efforts in authoring and applying the Events Analysis interface with compliance as part of its representation on the NERC Event Analysis Working Group (EAWG). NPCC has demonstrated implementation of the interface within its region as an example for the other regions.
- Provided essential support for the NPCC Criteria Compliance Enforcement Program (CCEP). Coordinated CC member ballot and approval of the CCEP-1 process document and CCEP-2 Implementation Plan to formalize the program; retired Criteria A–8, Guide B-22, and Procedure C-22, which was formerly implemented by the CMAS group; developed secure FTP process for Full member submittal of thirty (30) Criteria Certification forms and five (5) UFLS Implementation Plan Status reports submitted by Reliability Coordinators and Balancing Authorities; developed a "CC Member Restricted Area" location on the NPCC website and posted the submittals there; developed thirty (30) unique password accounts and instructions so that each member of the Compliance Committee could securely access and review submittals for CC member approval; provided summary "scorecard" of the secure submittals in preparation for CC member review and approval; conducted "landmark" first implementation of CC member review and approval of 2010 Criteria Certification Form submittals; developed draft CC Report to RCC with summary and results of CC Member Review and Vote; coordinated CCEP Working Group meetings to review and develop 2011 blank CCEP submittal forms, address Directory 12 UFLS Implementation Plan Status Report forms which were unique for each RC/BA.
- Compliance staff performed extensive review of new NPCC website and extensive cleanup and transfer of audit reports, schedules, and other existing compliance documentation that was missing from the old NPCC website. Reviewed and identified other documentation with diverse owners containing anomalies so that other stakeholders could take action to rectify.

To improve consistency of audits and other Regional activities:

- Participated on numerous NERC Committees and Working Groups to discuss and develop approaches, answers and tools to address topical issues and attain consistency among Regional Entities, including:
  - ✓ development of Auditor Tools and Auditor Manual;
  - ✓ review and redrafting of NERC Process Directive for Regional Entity Compliance Audit Report Processing;
  - ✓ revisions to RSAWs to correlate to latest versions of NERC standards;
  - ✓ working with other Regions and NERC in developing Audit Approach documents for several reliability standards to employ a consistent approach to audits. These include MOD-001, MOD-004, MOD-008, MOD-030, COM-002, FAC-003, PRC-005 and PRC-023. Additional Audit Approach documents are being developed based on the Tier 1 Actively Monitored List of Standards;
  - ✓ development and approval of random sampling methodology (RAT-STATS);
  - ✓ Industry vote for interpretations for Actively Monitored Standards (COM-002);
  - ✓ development, implementation and presentation to other Regions and NERC, methods that promote efficiency and consistency in applying the requirements outlined in NERC Appendix 4D of the Rules of Procedure (CCWGT); and,
  - ✓ attendance at CIP Version 5, Standards Drafting Team Meetings to provide feedback on the audibility of the new standards and share problems and experiences in auditing to the existing versions of the standards.
- Industry Workshop presentations:

  2011 NPCC Spring and Fall Compliance Workshops

  Compliance staff prepared and presented the following:
  - ✓ Auditing CIP standards;
  - ✓ Technical Feasibility Exceptions (Spring and Fall, 2011);
  - ✓ 2011 Audit Program and O&P audit observations;
  - ✓ ERO Events Analysis Process;
  - ✓ CIP Audit Observations;
  - ✓ Protection System Mis-operation Reporting and Compliance;
  - ✓ Set up NPCC Outlook Mailbox Workshop-Questions@NPCC.org to solicit topical Questions from attendees. Provided answers to submitted questions and classroom questions during the Workshop's 3 classroom sessions; and,
  - ✓ Audit Evidence substance and style (enhancements using audio technology).

  2011 NERC ERO Auditor Spring and Fall Workshops
  - ✓ Panelist participation for PRC-005 compliance and sampling (Spring 2011); and,
  - ✓ NPCC developed and gave presentation on Audit Approach to NERC MOD standards (Fall 2011). Presentation is posted on NERC's website under the Compliance; Regional Programs; ERO Workshop tab (Item V-A).

  Association of State Dam Safety Officials, Annual Dam Safety Conference (Washington DC)
  - ✓ Physical Security SME prepared presentations on the topics of Physical Security and CIP challenges to the Hydropower Industry - topics covered included most violated CIP Standards, Physical and Cyber security of Hydropower facilities, preparation for audits and regional audit approach.
- Participated in NERC Webinars and reviewed documentation on directives, CANS, and review of FERC orders for impact on audit scope to maintain awareness of topical issues affecting compliance and audits. All NPCC auditors attended at least one of the two ERO Auditor Workshops.

- Performed three (3) offsite and one (1) onsite joint Regional Entity audits - two (2) as lead region and two (2) as support Regional Entity. Differences in practices were critiqued at NPCC auditor meetings to reinforce NPCC interview approach and specific data handling processes.
- Provided input to NERC as requested: 2011 Audit status reports, 2012 Audit Schedule, audit reports for NERC Key Reliability Standard Spot Check (KRSSC) Program.

Goals	Threshold	Target	Stretch	Weight
Goal #4 Training, Education & Operator Certification Program	Establish a Regionally consistent implementation of NERC Standard PER-005 requirements – by 9/11.	Attainment of Threshold Goal and: Incorporate all posted lessons learned from the NERC event analysis program in the NPCC operator training seminars by 11/11.	Attainment of Target Goal and: Develop a Regionally consistent, systematic approach to training to design, develop and administer system operator training programs – by 12/11.	5

Goal #4 Training, Education & Operator Certification Program

Assessment of Goal Attainment: The Target attainment level for Goal #4 was achieved (100% of Target level achieved). At the NPCC System Operator Seminars conducted during 2011, NPCC presentations on the Event Analysis Process included: reasons for and the expected benefits from the new Process; discussion of what took place during Phases I and II of the field trial; the categories of events to be reported; the stages of the reports that must be provided by industry entities to NERC and the Regional Entities; the timing and level of detail for the required reports; and, lessons learned.

Supporting Materials and Background

The CO-2 System Operator Training Working Group has devoted portions of each meeting since 2007 to the sharing of the approaches used to satisfy the most significant of the NERC PER-005-1 "System Personnel Training" standard requirements, including R1.1, R1.1.1 and R1.2, that are needed to implement a systematic approach to training. In addition the content of the NERC Continuing Education Program and the NERC Continuing Education Administration Manual provides details on how to interpret and satisfy the requirements in PER-005-1. The basic PER-005-1 requirements are:

- R1.1 Create a System Operator Task List—Separate out reliability and market-related tasks
- R1.1.1 Update the Task List
- R1.2 Design and Develop Learning Objectives and Training Material
- R1.3 Deliver Annual Training
- R1.4 Program Evaluation of Training
- R2 Verify each of its System Operator's capabilities to perform each assigned task
- R3 Provide 32 hours of emergency operations training

In 2011 the NPCC System Operator Training Working Group (CO-02) has completed much of the work associated with requirements R1.1, R1.2 involving job task identification and job task analysis in the NERC Reliability Standard PER-005-1, "System Personnel Training."

While the NPCC RC/BAs are using slightly different approaches to satisfy the requirements, the collaboration among the CO-2 Working Group members has led to a shared approach to implementation within NPCC. This is to provide consistency on how the PER-005 standard requirements are satisfied. Key items with this include: 1) the content and level of detail in the system operator reliability-related task and sub-tasks used; 2) the ways job task analysis is being done by each RC/BA; and 3) shared use of a Task-to-Training Matrix.

The sharing of procedures and details for assembling and maintaining these programs has proven to be valuable because it allowed each area to improve their program while not requiring complete restructuring. This allowed the NPCC Area Operations Training programs to be similar, while still completely "personalized" to each RC/BAs.

In addition, sharing the experience each RC/BA has had during NERC Compliance Audits is also valuable in ensuring the RC/BAs build and maintain their respective programs to achieve compliance with all NERC Standards containing training requirements with special attention devoted to particular NERC standards such as the COM-002-2 "Communications and Coordination" standard, which addresses 3-part communication.

The Spring 2011 67th NPCC System Operator Seminar was held in early May, 2011 in Halifax, Nova Scotia. The table top exercise was on a progressive sabotage scenario and in addition a communication exercise was conducted. Presentations included: Nova Scotia Tidal Generation, Eastern Interconnection Frequency Response, the NERC Event Analysis Process and NPCC's role in it, facility additions and changes, system events/disturbances and outlook for 2011 summer operating conditions. The NERC/Region Event Analysis Process topic involved: 1) reasons for and the expected benefits from the new Process, 2) discussion of what took place during Phase I of the field trial, 3) the status of Phase II of the field trial, including differences from Phase I, 4) the categories of events to be reported, 5) the stages of the reports that must be provided by industry entities to NERC and the Regions and 6) the timing and level of detail for the required reports and 7) lessons learned. Seminar participants received Continuing Education Hours and presentation content was used for the balancing authority area training programs.

The Fall 2011 68th NPCC System Operator Seminar was conducted in November, 2011 in Niagara Falls. The table top exercise was a multi-topic operating strategy session with sharing of different approaches to similar situations, in addition a brief three-part communication exercise was done. Neighboring PJM trainers attended and participated in the seminar. Presentations included: an overview of the operation of the Niagara River System, PJM System Operation and Operator Tools, NPCC Current Activities which included a review of Event Analysis Process lessons learned since the start of the process, facility additions and changes, system events/disturbances and outlook for 2011-2012 winter operating conditions. Seminar participants received Continuing Education Hours and presentation content was used for the Balancing Authority area training programs.

In addition, NERC has reinitiated the Training and Education Group (TEG) to coordinate the development of Regional Entity and NERC staff training and registered entity education materials to support and continually enhance reliability. NPCC is actively participating on the group.

Goals	Threshold	Target	Stretch	Weight
Goal #5 Situation Awareness Program	Establish a systematic and repeatable NPCC event analysis process consistent with the NERC event analysis effort, including root cause analysis and Standards review; approved by the RCC – by 12/11.	Attainment of Threshold Goal and: Establish an automated NPCC event analysis data base - by 12/11.	Attainment of Target Goal and: Develop an automated event recommendations tracking system to facilitate monitoring recommendations generated by event analyses through to their implementation – by 12/11.	10

Goal #5 Situation Awareness Program

Assessment of Goal Attainment: The Target attainment level for Goal #5 was achieved. In May of 2011, the NPCC Events Data Base was established. Working in collaboration with the SERC IT Staff, NPCC Staff expanded a SERC data management tool, its "Events Capture System," to automate the NPCC event analysis process. The NPCC Events Data Base automatically assigns an event identification number for each qualifying event entered, provides tracking status for each step of the NERC review from initial Situational Awareness through, if required, the development of a NERC Event Analysis Report. All documentation and correspondence relevant to each unique event is stored and is immediately accessible and retrievable for the event. At the September 8, 2011, meeting of the NPCC Reliability Coordinating Committee, the RCC endorsed NPCC Document EAI-01, "Conducting NERC ERO Event Analysis Process," defining the NPCC Event Analysis Process consistent with the NERC Event Analysis Process.

Supporting Materials and Background

Following significant NPCC staff involvement in the developmental efforts, NERC is finalizing its event analysis program, the ultimate goal of which is to serve as a broad learning initiative to more rapidly disseminate to the industry those lessons learned in the analysis of a system event from which the industry may profit through enhanced reliability. By integrating a "bottom-up" approach to a disturbance review within the framework of the event analysis program, consistency, comparability, flexibility and timeliness in the event analysis process will be promoted. During 2011, NPCC Staff assisted in the coordination of two field trials of the NERC Event Analysis process, soliciting and incorporating the comments and recommendations of the industry in a final draft process document submitted to the NERC Planning Committee and NERC Operating Committee at their respective meetings of December 13 and 14, 2011. The elements of this process are now being integrated into the NERC Rules of Procedure.

The manner in which the registered entities, NPCC and NERC evaluate and analyze system disturbances is critical to the understanding of the event and the gleaning of lessons to be learned to enhance operational performance, to prevent a similar event from reoccurring or to mitigate the future consequences of such an event. Effective event analysis must: identify as quickly as possible what happened; establish the sequence of events associated with the disturbance; realize the cause or causes of the event; implement corrective actions; and, disseminate recommendations and lessons to be learned to the industry.

In its implementation of the process, NPCC has established a team of staff members to provide outreach to the registered entities to facilitate their engagement in the event analysis process, to discuss disturbances as they occur, to guide the membership in the expectations of the process and

to answer any questions as they arise. An automated data base has also been established at NPCC to catalog events, reports and lessons learned and facilitate the monitoring of the effort by NPCC Staff.

Operational Awareness Tools

Reliability Indicators

NPCC has completed the first phase of the FERC-NERC-Regions situation awareness initiative, NERC Situational Awareness-FERC, NERC, Regions (SAFNR). At the request of the FERC, the Reliability Coordinator Areas have developed procedures to provide to the FERC detailed operating data for their respective footprints. The intent of the effort was to permit the FERC to measure the health of the Interconnections and to identify parameters which may warn of a developing crisis, thus precluding a major cascading event. To fulfill its portion of the first phase effort, NPCC implemented a geographically based visualization of selected reliability indicators. NPCC Staff and each Reliability Coordinator of NPCC has access to near real time displays depicting a geographic visualization of the complete NPCC footprint.

In 2011, NPCC staff actively supported NERC in its development of the second phase of the SAFNR effort, which will enhance the SAFNR visualization tool by providing more detailed line flow information and commonality across all Regions in the display formats.

Operating Tools

Integration of Wind Farms

The Working Group IST-2 is completing a review of the communications of operational telemetry to ensure that the security of such data can be maintained as the increased amounts of variable generation is added to the system.

System Restoration

Wide-Area Restoration Drill

The CO-11 Working Group organized an enhanced, wide area restoration drill among the Reliability Coordinators of NPCC and their neighboring Reliability Coordinator areas. The joint wide area restoration simulation among the Reliability Coordinators of NPCC, as well as their counterparts in the Midwest ISO and PJM, was conducted by the CO-11 Working Group CO-11 in October 2011.

In 2011, the NPCC Restoration Working Group (CO-11) developed new drafts of NPCC Regional Reliability Reference Directory No. 8, “System Restoration,” and former Type C Procedure NPCC Document C-35, "NPCC Inter-Area Power System Restoration Procedure."

High-Impact, Low Frequency (HILF) Event Risk Initiatives

In 2011, NPCC participated in five active NERC Task Forces formed to pursue the recommendations of the joint NERC and United States Department of Energy report, "High-Impact, Low-Frequency Event Risk to the North American Bulk Power System," released in June 2010.

NERC Geomagnetic Disturbance (GMD) Task Force

NPCC Members and members of the NPCC Task Force on Coordination of Operation have contributed in 2011 to the NERC Geomagnetic Disturbance Task Force, the draft report of which will be directed to the NERC Standing Committees for comment in January 2012.

NPCC has measures in-place to respond to GMD events, through the Geomagnetic Storm Mitigation System (GSMS) provided by the Solar Terrestrial Dispatch. The GSMS is a solar notification and communication system for the five Reliability Coordinators of NPCC. An active

communications software package installed on the system operator's console provides each of the NPCC Reliability Coordinators with geomagnetic storm alerts and the ongoing status of solar activity.

NERC Severe Impact Resilience Task Force

NPCC Members and members of the Task Force on Infrastructure Security and Technology have contributed in 2011 to the NERC Severe Impact Resilience Task Force, the draft report of which will be directed to the NERC Standing Committees for comment in January 2012.

NERC Spare Equipment Database Task Force

In 2011, NPCC staff participated in the development of the NERC Spare Equipment Database Task Force. NPCC staff will act as the Regional Entity Coordinator to help coordinate the Spare Equipment Database (SED) which is a NERC sponsored initiative to establish a listing of spare transmission equipment that require six months or more to manufacture. NERC registered Transmission Owners and Generator Owner are expected to voluntarily list their spare transformer and GSU equipment (100 kV and above) in a secure database format which can be used by entities faced with long-lead times to replace damaged equipment in the aftermath of a HILF events. NERC currently has a signed contract with Open Access Same Time Information Systems to deliver a web based tool by the second quarter of 2012.

NERC Smart Grid Task Force

Members of the Task Force on Infrastructure Security and Technology are contributing to the ongoing efforts of the NERC Smart Grid Task Force.

NERC Cyber Attack Task Force

Members of the Task Force on Infrastructure Security and Technology are contributing to the ongoing efforts of the NERC Cyber Attack Task Force.

System Preparedness

Weekly Conference Call

NPCC staff coordinated this weekly effort which helps to ensure electric system reliability. Timely summary reports were issued to operations staff throughout NPCC and to PJM and Midwest ISO for all 52 weeks of 2011. These calls and summary reports have taken place and have been issued without exception for at least the last 13 years.

NPCC staff continues to pursue possible options to automate the data entry process on the part of the Reliability Coordinators.

Daily Conference Call

Each morning, the NPCC Reliability Coordinator control rooms, as well as the RCs for MISO and PJM, take part in a regularly scheduled conference call to enhance system situational awareness. The goal of this call is to alert all neighboring Reliability Coordinators of any potential emerging problems which could lead to reliability concerns in the course of the day's operations. Subjects for discussion are limited to credible events which could impact the ability of a Reliability Coordinator to serve its load and meet its operating reserve obligations, or which would impose a burden to the neighboring NPCC Reliability Coordinators or the Eastern Interconnection.

Emergency Preparedness Conference Call

Three emergency preparedness calls were held during the week of July 20-22, 2011when a heat wave resulted in very heavy demands throughout the U. S. Midwest, northeastern U. S. and

eastern Canada. ISO-New England and NYISO all-time would have been exceeded during that period except that large amounts of demand response were used to provide load relief.

Six emergency preparedness calls were held prior to and during Hurricane Irene during the August 25-29, 2011 period. These calls enhanced system situational awareness and provided great assistance in planning operations during the coming day or hours among the NPCC Reliability Coordinators, PJM, and the Midwest ISO. NPCC staff coordinated the calls and issued notes.

NPCC Staff also participated in the RRO-NERC-Regulatory conference calls which were held during Hurricane Irene and Winter Storm Alfred.

Emergency Telecommunications Coordination

NPCC staff, working with the Reliability Coordinators and the IST-2 Working Group (IST-2) determined that voice communications were adequate for emergencies, as all Areas had at least both primary and backup voice communication systems. The monthly tests from November 2010 to October 2011 have shown that the Iridium satellite communications to/from ISO-NE, NYISO, IESO, NBSO and TransEnergie were successful.

The NPCC System Operations Managers Working Group (CO-08) has revised and updated NPCC Regional Reliability Reference Directory 1, "Design and Operation of the Bulk Power System."

NERC Alerts

For each NERC Alert, NPCC staff and the Task Force on Infrastructure Security and Technology actively coordinates a review among the NPCC Members of their understanding of the implications of the Alert and their expected response. In 2011, two NERC Alerts received particular focus:

Facility Ratings

The NERC Alert addressing facility ratings, “Consideration of Actual Field Conditions in Determination of Facility Ratings,” was issued by NERC on October 7, 2010, recommending that Transmission Owners (TOs) and Generator Owners (GOs) verify that the methodology used to determine the facility ratings associated with overhead transmission is based on actual field conditions. The NERC proposed a time frame of three years to conclude the effort, with priority given to facilities deemed High Priority, Medium Priority and Low Priority. The registered entities were asked to designate the three prioritization categories into which their facilities would be assigned together with their plan for meeting the NERC timeframe. High Priority facilities would be reviewed in calendar year 2011, Medium Priority facilities would be reviewed in calendar year 2012 and Low Priority facilities would be reviewed in calendar year 2013. The Regions were charged to assess the plans of the entities and to monitor the response of the industry to the Alert, and NPCC has actively worked with its registered entities in this undertaking.

NPCC staff verified that all 167 of the registered TOs and GOs in NPCC replied to the Alert in a timely manner. Through early June, NPCC Staff had reviewed, and discussed with the entities, all of their responses to the Alert. Based on the revised criteria issued by the NERC on April 26, 2011 (providing criteria through which certain entities may be excluded from the Alert), eleven GOs continued to be monitored by NPCC. Among the Transmission Owners, twenty-three entities continue to be monitored. All of the plans were judged acceptable. As part of this tracking, NPCC provided to NERC a status report of these thirty-four ongoing facility reviews

on July 15th; a year end summary will have been provided on January 15th, and such status reports will be provided until the conclusion of the effort at the end of calendar year 2013.

To date, twenty discrepancies resulting in facility deratings have been identified by field inspections, of which ten have already been mitigated; ten deratings remain in effect.

AURORA

NPCC Members reviewed the two update requests from NERC in response to the ongoing AURORA Alert, "AURORA Mitigation-Protection and Control Engineering Practices and Electronic and Physical Security Mitigation Measures." NERC will continue to monitor the industry response to the Alert to its completion.

Goals	Threshold	Target	Stretch	Weight
Goal #6a. Reliability Assessment & Performance Analysis Program	Provide active NPCC participation in NERC Revision the Definition of the Bulk Electric System initial draft BES definition – by 5/11	Attainment of Threshold Goal and: BES definition, exception criteria and Rules of Procedure exception process developed, consistent with NPCC input – by 12/11	Attainment of Target Goal and: Achieve NPCC objectives of : "intelligent bright line", technically based exception process, and transitional implementation period in NERC BOT approval of related BES filings – by12/11	15

Goal #6a Reliability Assessment & Performance Analysis Program

Assessment of Goal Attainment: The Stretch attainment level for Goal #6a was achieved. Ballots for the Definition of Bulk Electric System and associated implementation plan, and for the application form titled 'Detailed Information to Support an Exception Request' referenced in the Rules of Procedure Exception Process concluded on November 21, 2011, both with a weighted segment approval of over 81%. Because of timing issues around the December holidays, the NERC BOT consideration was ultimately scheduled for January 18, 2012, in advance of the January 25, 2012 filing deadline.

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Supporting Materials and Background

In Order 743, the Federal Energy Regulatory Commission (FERC) directed NERC, through their Reliability Standards Development Process, to revise the definition of the Bulk Electric System (BES) to improve clarity, reduce ambiguity, establish consistency across all Regional Entities within the U.S., and ensure that the definition encompasses all facilities necessary for operating an interconnected electric transmission network.

Pursuant to the Final Rule, NPCC staff has actively participated in every face-to-face meeting and teleconference of the NERC Standards Drafting Team formed to review the definition of the BES and corresponding changes to the NERC Rules of Procedure (RoP). NPCC staff was asked to assist in the conduct of two NERC sponsored BES Webinars; over 800 industry representatives participated in those Webinars.

NPCC staff provided timely updates to the NPCC Board through written meeting summaries and Board presentations. In addition, NPCC staff provided presentations on the subject at the 2011 Spring and Fall Compliance and Standards Workshop, and at the 2011 NPCC General Meeting.

The following BES Project milestones were met:

- BES Standard Authorization Request Finalization - posted December 17, 2010 - January 21, 2011
- Initial Draft of BES Definition – posted May 11 – June 10, 2011
- Complete Formal Comment & Ballot – posted September 30 – October 10, 2011
- Recirculation Ballot – posted November 10 – November 21, 2011
- BES filing – submitted for NERC BOT consideration scheduled for January 18, 2012

Two recirculation ballots, one for the Definition of Bulk Electric System and associated implementation plan, and one for the application form titled 'Detailed Information to Support an Exception Request' referenced in the Rules of Procedure Exception Process concluded on November 21, 2011.

Both recirculation ballots achieved stakeholder approval. The ballot for definition of BES achieved a quorum of 95.92% and a weighted segment approval of 81.32%. The ballot for the application form titles 'Detailed Information to Support an Exception Request' achieved a quorum of 93.02% and a weighted segment approval of 81.48%. 113 sets of comments, including comments from more than 75 different people from approximately 45 companies representing eight of the 10 Industry Segments were considered and addressed.

NPCC staff was instrumental in achieving the following NPCC Board of Directors BES policy input during its extensive deliberations with the BES Drafting Team:

- moving the development of a BES Exception Process Criteria from the Rules of Procedure Team to the BES Drafting Team;
- posting of a draft BES Exception Process Criteria for parallel review with the 1st Draft BES Definition for industry comment;
- development of a BES Exception Process Criteria that allows for the exclusion of distribution facilities as identified through the application of appropriate criteria, such as those contained in the FERC 7 Factor Test;
- the concurrent second postings of the BES definition and the BES Technical Principles for Demonstrating BES Exceptions with the consideration of comments received;
- a BES Definition and Technical Principles for demonstrating BES Exceptions that respects the statutory limits imposed under FPA 215 to not include facilities used in the local distribution of electric energy as established by applicable regulatory authorities; and,
- consistency between the BES definition and the Compliance Registry criteria.

The NPCC Board also acknowledged that the developed NERC BES Definition was responsive to the directives of the FERC Order. The NPCC objectives to achieve an "intelligent bright line, a technically based exception process, and a transitional implementation period, consistent with the expectations of the Final Rule were met.

BES Exception Process – revision to NERC Rules of Procedure

NPCC staff and through its consultant representative worked to develop a BES exemption process that includes clear, objective, transparent, and uniformly applicable procedure for the exemption (exclusion/inclusion) of BES facilities from the 'bright-line' BES definition. In order to avoid an inconsistent application of the exemption process, NERC will oversee the exemption process executed by the Regional Entities in order to ensure an objective and uniform application.

Concurrent with the development of the revised Bulk Electric System definition, a Bulk Electric System Rules of Procedure Team ("BES RoP Team") was formed to develop a procedure for processing exceptions to the Bulk Electric System definition. The BES RoP team developed a second draft of the proposed Appendix 5C Bulk Electric System Component Exception Procedure, which was posted along with several related documents for comment for 45 days (from September 13, 2011 through October 27, 2011).

NPCC has worked extensively with the BES RoP Team, in order to shape the BES exception proposals to be consistent with the expectations of the Final Rules, and NPCC policy direction.

NPCC BES Transition/Implementation Plans

FERC directed NERC to work with the Regional Entities affected by the Final Rule to submit for Commission approval transition plans that allow a reasonable period of time for the affected entities within each region to achieve compliance with respect to facilities that are subject to Commission-approved Reliability Standards for the first time based on a revised bulk electric system definition. The Commission stated that it expects that NPCC is the only region that will be significantly affected. FERC directed NERC to file the proposed transition plans within one year of the effective date of the Final Rule.

NPCC is currently in the process of coordinating the review of NPCC transition plans through the NPCC Compliance Committee.

Goals	**Threshold**	**Target**	**Stretch**	**Weight**
Goal #6b. Reliability Assessment & Performance Analysis Program	Simulate and analyze potential mitigation measures (a/k/a Task 5 of the August 14, 2003 Northeast Blackout Study Plan) and obtain Task Force approval – by 12/11. Establish the technical parameters for a secure and reliable NPCC region wide program for the sharing of operating reserve for approval by the TFCO – by 8/11.	Attainment of Threshold Goal and: Develop recommendations based on mitigation measures study results and obtain RCC approval of study report – by 11/11. Develop a process to evaluate reliability impacts of participation in an NPCC regional reserve sharing program for RCC approval – by 12/11.	Attainment of Target Goal and: Coordinate mitigation measures study results and recommendations with the New York State reliability Council Defensive Strategies Working Group – by 12/11. Achieve RCC approval of ballot posting directory governing an NPCC Reserve Sharing program – by 12/11.	10

Goal #6b Reliability Assessment & Performance Analysis Program

Assessment of Goal Attainment: The Target attainment level for Goal #6.b. was achieved. At its November 29, 2011 meeting, the RCC unanimously approved the SS-38 Task 5 Study Report's assessment of potential measures that may prevent or mitigate the impact of major system disturbances originating from a wide range of initiating events. A proposed draft of the new NPCC Regional Reliability Reference Directory No. 6, "Reserve Sharing Groups," was finalized at the meeting of the NPCC TFCO held in August, 2011, and subsequently posted for public comment.

Supporting Materials and Background

At its November 29, 2011 meeting, the RCC unanimously approved the SS-38 Task 5 Study Report. This study effort completed the final task of the 2003 Blackout Study in the assessment of potential measures that may prevent or mitigate the impact of major system disturbances originating from a wide range of initiating events. NPCC members should benefit from the information that Task 5 study results provided. Task 5 study results have also been closely coordinated with the NYISO and the NYSRC who have also been conducting the New York Controlled Separation Study funded through a DOE grant.

A proposed draft of the new NPCC Regional Reliability Reference Directory No. 6, "Reserve Sharing Groups," was finalized at the meeting of the NPCC Task Force on Coordination of Operation (TFCO) held on August 11 and 12, 2011, and subsequently posted for public comment. The document established the framework for the reliable implementation of the sharing of operating reserve within NPCC, supplanting the original Type C Procedure C-38, "Procedure for Operating Reserve Assistance." The comments to the first posting have been reviewed by the TFCO, and, following a response to the comments, the document will be submitted to the NPCC Reliability Coordinating Committee (RCC), seeking approval for ballot. The draft includes the requirement for the quantification of the change in the reliability risk associated with a proposed reserve sharing agreement to be presented to the TFCO.

Following its approval, the new Directory No. 6 will also serve as the core of a new Regional Standard to be developed by the Task Force on Coordination of Operation.

Model Development and Improvement

Develop the MMWG 2011 library of power flow and dynamic models in accordance with the approved schedule and initiate efforts to improve the accuracy of the models. Enhance regional procedures for validation of data used in power flow and dynamic simulations and benchmark against actual system performance

NPCC staff participated in the ERAG, NERC and MMWG efforts to improve the accuracy of Wide-Area regional transmission models utilized in long-term and event analysis. The MMWG 2011 library of power flow and dynamic models was completed in accordance with the approved schedule. NPCC staff also participated in the NERC Eastern Interconnection frequency study to analyze generator governor response to frequency excursions.

NPCC staff participated in the NERC Model Validation Task Force's (MVTF) effort in developing procedures to be used to validate both power flow and dynamics models used in base cases. A field test for these procedures will be carried out in 2012. The MVTF are also looking at ways to improve Powerflow Solution Algorithms.

NPCC staff researched papers and past industry effort that went into the development of improved load modeling. The information obtained is critical in helping jump start the planned 2012 NPCC effort to address the remaining recommendation from the 2003 Blackout Study to develop an industry guideline for load modeling.

Review 2011 summer base case frequency response to ensure it correlates with unit commitment, complete the survey of NPCC governor response, and develop a white paper that identifies NPCC Guidelines for load modeling in transmission system analyses

NPCC staff activity contributed to the efforts of the ERAG Management Committee and Multi-regional Modeling Working Group, are working jointly with NERC, on a testing proposal to examine the modeling of overall Eastern Interconnection frequency response. The testing is intended to help assess changes in modeling needed to improve correlation of simulated

frequency response with actual events before going through the full process of establishing better models unit by unit (i.e. going to generating plants and evaluating operation and running system tests).

The testing consisted of: 1) disabling all existing governor models, 2) developing a set of scenarios of fully responsive on-line generator governor frequency response (e.g. 30%, 20%, 10%), 3) for each scenario, insert generic governor models into the study case for the designated percentage of capacity in each category, 4) observe system response in the simulations and compare to observed governor response for system events that involve capacity or load loss with system frequency impacts, 5) assess which scenario(s) best match the Eastern Interconnection frequency response from actual events.

The first sets of tests were done in October and results are currently being evaluated.

Provide leadership for NPCC-RFC Activities

NPCC staff acted as the Chair of the RFC-NPCC Inter-regional Working Group, and planned, organized and direct this engineering group in conducting and producing the summer and winter period inter-regional transmission capability assessments. This year's winter period study was replaced by an assessment of the 2020 summer period.

The Eastern Interconnection Reliability Assessment Group's SERC east-RFC-NPCC Working Group and Steering Committee's 2011 summer and 2020 summer RFC-NPCC Assessment Reports were completed and issued on schedule.

In 2011, NPCC staff participated in the development of the ERAG Combined Study Procedure Manual.

Technical Support of NPCC Reliability Criteria Development

Provide technical input to the Open Process Review of NPCC Directory No. 1

NPCC completed a comprehensive CP-11 Working Group review of the NPCC Directory No.1, Design and Operation of the Bulk Power System, to assure that it is consistent with other NPCC Directories, Criteria, Guidelines and Procedures and with applicable NERC Reliability Standards, and a rewrite of criteria requirements into more specific and measureable requirements to support the NPCC Criteria Compliance Enforcement Program. The draft revised Directory No. 1 with its phase 2 criteria requirement conversion has been submitted to the Task Forces for their final review and endorsement prior to posting it in the NPCC Open Process Review.

Support Phase 2 of the NPCC Directory Project

A revised and enhanced NPCC Regional Reliability Reference Directory 5, "Reserve," clarifying the implementation of Simultaneous Activation of Ten Minute Reserve (SAR) following a radial source contingency, was developed during 2011 and has been posted for public comment.

NPCC staff led several Task Forces in completing a comprehensive review of Directory No. 7, Special Protection System Criteria. Draft revised Directory No. 7 is expected to be posted in Open Process Review in early 2012.

The NPCC Task Force on Coordination of Operation revised NPCC Regional Reliability Reference Directory No. 9, "Verification of Generator Gross and Net Real Power Capability," and NPCC Regional Reliability Reference Directory No. 10, "Verification of Generator Gross and Net Reactive Power Capability" were approved by the RCC at its November 29, 2011 meeting.

On December 28, 2011 NPCC Membership approved the revised versions of NPCC Regional Reliability Directories Nos. 9 and 10.

Reliability and Adequacy Assessments

Complete the NPCC Tie Benefits Analysis

The NPCC Task Force on Coordination of Planning reviewed the "*Review of Interconnection Assistance Reliability Benefits"* report at its May 11, 2011 meeting and agreed with its main conclusions:

- that the methodology and assumptions used in this Review were consistently applied to all NPCC Areas, using the same multi-Area reliability model,
- that the NPCC Area estimates of the interconnection benefits used to meet the NPCC Resource Reliability Criterion were reviewed on a consistent basis; and,
- that the interconnection assistance values reported by the NPCC Areas in their recent resource adequacy assessments appear to be reasonable and do not overstate interconnection benefits.

The RCC approved the report at its meeting on June 1, 2011.

Conduct the 2011 NPCC Multi-area Probabilistic Long-Range Adequacy Overview

Due to the delay in the approval of the NERC 2011 Long-Term Reliability Assessment (LTRA) on which it is based, the 2011 NPCC Long Range Adequacy Overview will be presented to the RCC for review and approval at its March 2012 meeting, following NPCC's Task Force on Coordination of Planning review.

The Overview evaluates the near term and long-range (five year) adequacy of NPCC Areas, reflecting neighboring regional plans proposed to meet their respective resource adequacy planning criteria, including estimates of probabilistic metrics approved by the NERC Planning Committee for consideration in future NERC Long-Term Reliability Assessments.

Conduct the NPCC 2011 Summer and 2011/2012 Winter NPCC Reliability Assessments, and obtain TFCO and RCC approvals

The CO-12 Working Group completed and issued the NPCC 2011 summer and 2011/2012 winter NPCC Reliability Assessment Reports. The CP-8 Working Group's Multi-Area Probabilistic simulation results and report documentation were included in the NPCC Reliability Assessment Reports. Presentations providing the results of the assessments were provided to the Task Force on Coordination of Operation at their February and October meetings and to the Reliability Coordinating Committee at their November 29, 2011 meeting.

Coordinate NPCC area input and report review associated with the NERC 2011 Long-Term Reliability Assessment (LTRA), including NERC Scenario Analysis, and NERC pre&post Seasonal Assessments

The NERC Reliability Assessment Subcommittee (RAS) 2011 summer and 2011/2012 winter draft LTRA and data were all provided to NERC on time; all NERC RAS peer review comments were addressed and questions answered to finalize the NPCC input to the RAS reports. The LTRA report included a section that updates NERC's "*2010 Special Reliability Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*."

The 2010/2011 winter and 2011 summer post assessment NERC assessment and data were provided to NERC on schedule. In addition, NPCC input was provided for the NERC "*2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power*

Interdependency in the United States", which reviews gas and electric interdependencies, assesses existing and future challenges, identifies areas of vulnerability, and provides recommendations for enhancing reliability. This NERC Special Reliability Assessment was approved by the NERC Planning Committee and BOT and released in December, 2011.

Review and Analyze NPCC Protection System Mis-operations

NPCC staff, in coordination the NPCC Compliance Committee, and the Task Force on System Protection, addressed the significant challenge regarding protection system mis-operations identified by NERC as the number one reliability concern in the Industry. Through extensive effort by Staff and NPCC members, both technical (C-45) and compliance (CP-7) procedures were established in NPCC for reporting and reviewing specified protection mis-operations on a quarterly basis in a consistent format. All quarterly reported mis-operations are being reviewed by the NPCC SP-7 Working Group and reported by Staff to the RCC and to NERC. Trending and performance metric are being established to address this reliability concern.

NPCC staff participated in the ERO-RAPA initiative to assess the application of Special Protection System (SPS) among the eight Regions. This extraordinary effort is expected to lead eventually to the development of a common set of requirements and definition for SPS and revisions to the existing NERC standard.

Reliability Metrics

Developed the "*NERC RIS Probabilistic Assessment for the NPCC Region***"** report for the NERC Resource Issues Subcommittee (now part of the Reliability Assessment Subcommittee) that provides the requested probabilistic reliability metrics and documents the assumptions and approaches used to implement the methodology within NPCC, as a trial for inclusion in future NERC Long Term Reliability Assessments. In addition, a comparison of NPCC's 2010 and 2011 NPCC Long Range Adequacy Overview results of the hourly Loss of Load Expectation (LOLE) and annual Expected Unserved Energy (EUE) probabilistic metrics covering the requested future five-year period was given at the NERC LOLE Best Practices Working Group in November 2011.

NPCC staff actively participated in the ERO-RAPA Group's activities related to NERC data collection requests in support of developing NERC Reliability Metrics, including:

- ✓ Consistent Regional reporting of Relay Mis-operations
- ✓ Regional support of NERC TADS, and the start-up of DADS, GADS, and the SED
- ✓ Documenting Underfrequency Loadshedding operation
- ✓ Identifying Operating Procedures assumed in conduct of TPL studies
- ✓ Classification and number of Special Protection Systems
- ✓ Monitoring voltages at critical system locations

As the 2011 NPCC Transmission Availability Data System (TADS) Regional Coordinator, NPCC staff reviewed all required data entry related to transmission line and equipment outages recorded in the NERC WebTADS Information System, and provided oversight of the NERC TADSTF activities. NPCC staff reviewed accuracy of the TADS database with respect to NERC PRC and ALR standards.

As the 2011 NPCC Demand Response Availability Data System (DADS) Regional Coordinator, NPCC staff assisted member reporting entities in preparation for required data entry related to demand response recorded in the NERC WebDADS Information System, and provided oversight of the NERC DADSTF and DADSWG activities.

As the 2011 NPCC Generating Availability Data System (GADS) Regional Coordinator, NPCC staff providing oversight for member reporting entities and designated reporting entities in advance of beginning of mandatory GADS reporting period.

Additional Achievements

NPCC staff, in conjunction with SS-38, TFSS, and the RCC, completed the comprehensive review and approval of proposed set point changes submitted by owners of nuclear generating units with motor-generator set with effective threshold settings greater than allowable by the NPCC UFLS program.

NPCC staff also provided expertise and its Criteria A-10, Classification of Bulk Power System Elements as a model in the NERC development of a screening test within the Data Request expected to be implemented in early 2012 to address FERC Order 754 related to single point of failure of protection systems at significant impact facilities in system planning studies.

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I.	**Enhance Northeast Reliability** - Enhancing reliability of the Bulk Electric System is an overarching goal that drives the activities of NPCC.	**Weighting: 50% of Total**		
1.	**Reliability Standards – 6%**	**Threshold**	**Target**	**Stretch**
a.	***Improve Reliability through Improved and Coordinated Standards Reviews*** Conduct thorough reviews of all NERC standards being developed or revised, and coordinate comments for Northeastern North America. In addition, study, propose and implement processes and reviews of feedback mechanisms for Compliance and Events Analysis to ensure that lessons learned result in improvements to the standards. Also review all regional standards with the other regions for potential "Eastern Interconnection" standards and possible existing Continent wide standards that can have an EI standard developed to augment it to potentially achieve a higher level of reliability.	Conduct a review of Regional Standards under development within the Eastern Interconnection to determine opportunities to develop coordinated EI standards and provide the results of this analysis to the RSC and RSG - by 12/12.	In addition to attainment of threshold, develop a process for a "feedback" mechanism from NPCC Compliance and NPCC Events Analysis into the standards process and implement it - by 12/12.	In addition to attainment of Target, draft a potential NERC feedback process and receive RSC approval of such feedback process and transmit the process to the NERC SC and RSG for their use and implementation – by 12/12.
b.	***Improve Reliability through Improved Standards Processes*** Conduct thorough reviews of all NERC standards development processes. Review the NPCC Reliability Standards Development Procedure. Productivity and developing quality, effective and reliability enhancing standards should be the focus of NERC as the ERO. The Regions should support this and identify any opportunities to improve their respective standards development process to at least achieve an equally efficient and effective program that is as consistent with the other Regions as possible.	Participate in the NERC SC and SCPS to provide review and comment of NPCC stakeholders regarding the existing processes. Complete collections of these comments and meet all NERC deadlines using the RSC to coordinate – by 12/12.	In addition to attainment of threshold, develop a set of proposed improvements, achieve approval by the RSC and Implement them in a new Reliability Development Procedure - by 12/12.	In addition to attainment of Target, draft potential NERC process improvements for standards development and receive RSC approval of such improvements and transmit to NERC SC and SCPS for their use and implementation – by 12/12.
2.	**Compliance Audits and Investigations – 12%**	**Threshold**	**Target**	**Stretch**
a.	***Improve Remote Data Security*** Use new technology to implement improved and advanced remote access technologies to allow more secure transmission of data between NPCC and Registered Entities. This will also stabilize travel costs; enable more efficient use of auditors' time; be less burdensome to audited entities; and facilitate more advanced cyber security. Key metrics would include pre / post implementation travel hours and number of audits, and TFE reviews completed per year. There are many remote access solutions currently available. The key is to find one that enables NPCC to more effectively and securely transfer and store confidential files.	Research and choose an advanced remote access solution that ensures enhanced secure transfer and storage of confidential files - by 6/12.	Test and implement the remote access solution - by 9/12	Provide the services during on-site visits and workshops necessary to ensure that 50% of registered entities are using the new remote access - by 12/12
b.	***Enhanced Reliability Focused Spot Check Program*** Develop and implement the 2012 spot check program that increases the 2011 program by 10%, to enhance focus on the most violated standards and high impact standards in the NPCC Region. Increased focus on the most violated standards, and other standards that have high impact will increase reliability of the BES.	Develop 2012 spot check program, increasing the 2011 program by 10%, to enhance focus on the most violated standards and high impact standards in NPCC - by 2/12.	Achieve threshold level, adding spot checks for 80 registered entities using risk-based methodology and performance based auditing – by 10/12	Implement results and lessons learned with registered entities, REs and NERC for future actively monitored list and focused audits - by 12/12.

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c.	***Implement entity suggestions to improve the audit process*** Identify and implement registered entity suggestions to improve the audit process, and provide an update to entities on the feedback from audits. Review all comments presented by entities in their Audit Feedback Forms and incorporate those that benefit us into the NPCC audit program.	Review all suggestions and implement the top five (5) that appear to be the most beneficial – by 12/12	Provide results of the audit feedback review and implementation at the two NPCC Compliance Workshops. Post the 2012 Audit Feedback Results summary periodically on the NPCC website – by 12/12.	Incorporate policy changes into NPCC procedures for the audit program. Provide results of NPCC feedback and implementation to other Regional Entities and NERC to promote consistency - by 12/12.
d.	***Auditor input on audit process and entity compliance*** Develop an enhanced Auditor Feedback form to be completed by each auditor at the end of every audit. Specific questions covering audit logistics and entity compliance, as well as suggestions for improvement will be solicited, and potentially used as input into a feedback mechanism for standards development. This will provide timely, relevant, and documented observations and specific feedback from the auditors. Auditor Feedback forms will assist in improving audit processes, thus benefiting NPCC, the audited entity and NERC. Reliability Standards issues that are of concern will be identified to NERC and NPCC Standards area..	Develop a draft enhanced Auditor Feedback form - by 2/12.	Collect survey information for all 2012 NPCC audits, analyze results, compile data and also compare to corresponding Post- Audit Feedback received from audited entities – by 12/12.	Utilize results of Auditor Feedback to implement changes to NPCC internal Culture of Compliance initiative and changes in existing Reliability Standards – by 12/12
3.	**Compliance Registration and Enforcement - 12%**	**Threshold**	**Target**	**Stretch**
a.	As an extension of the 2011 Culture of Compliance Initiative, develop additional risk-based components and criteria to be used to perform an overall Entity Impact Evaluation of all registered entities. These risk-based components and criteria will take into account various aspects related to a registered entity such as, but not limited to: physical assets, reliability performance, Culture of Compliance, compliance history and Regional experiences (e.g. from compliance audits, spot checks, etc.) The Entity Impact Evaluation will be designed as a stand-alone activity to evaluate all of NPCC registered entities, from multiple risked-based aspects and categorize their overall impact on the reliability of the Bulk Electric System.	Develop the components and criteria for an Entity Impact Evaluation – by 12/12	Attainment of Threshold goal and the development of the methodology for determining a registered entity's impact evaluation - by 12/12.	Attainment of Target goal and the completion of a detailed Entity Impact Evaluation of 15 companies from a cross section of NPCC registered entities, including a comprehensive review of the evaluation with each entity to discuss the results. - by 12/12.
b.	***Expedited and Complete Mitigation Plan Submittal:*** Expedite the submittal of accurate and complete mitigation plans, by registered entities, for all violations identified. Compliance throughput will enhance with all mitigation plans submitted before a NOPV is sent to the registered entities for possible violations. NPCC enforcement staff will be the stimulus for ensuring that mitigation plans are submitted in a timely fashion so that a possible violation's mitigation plan has corrective measures in place to prevent a reoccurrence, resulting in an improvement in the reliability of the bulk electric system.	Receipt of all required mitigation plans and mitigating activities for all identified violations – by 12/12	Attainment of Threshold goal and receipt of 50 % of required mitigation plans before issuance of a Notice of Alleged Violation and Proposed Penalty or Sanction (NAVAP) – by 12/12.	Attainment of Target goal and receipt of all required mitigation plans before issuance of a NAVAP – by 12/12.

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4.	Training, Education & Operator Certification Program – 6%	Threshold	Target	Stretch
a.	Develop and deliver presentations at NERC Modeling Seminars to industry entities to improve steady state and dynamics modeling of equipment that provides system frequency response. This is to gain the cooperation of Eastern Interconnection Reliability Coordinators, Transmission Operators, Transmission Owners, Generation Operators, Generation Owners and Planning Authorities to obtain and refine the data needed in steady state and dynamics models to more closely reflect actual characteristics.	Develop presentations and obtain actual system information to convincingly show a need for Eastern Interconnection entity assistance to ERAG. Obtain ERAG Management Committee and NERC approval. – by 4/12	Attainment of Threshold Goal and: Deliver presentations at NERC Modeling Seminars to get industry entity concurrence to improve equipment modeling. Focus is on modeling of equipment that contributes to system frequency response. – by 9/12	Attainment of Target Goal and: Incorporate comments and feedback from Modeling Seminars and ERAG Management Committee in frequency response modeling presentations. Provide reports on the modeling improvement effort to the RCC. Incorporate system frequency response improvement effort content in Spring and Fall 2012 NPCC operator training seminars –by 11/12.
b.	Develop consistent approach to operator training, evaluate existing programs, and verify implementation of any modifications Training	Develop Regionally consistent implementation of NERC PER-005 requirements for a systematic approach to training. Collaborate on methods and approaches to meet Requirement R1.4 to ensure all steps are addressed in analyzing, designing, developing, implementing and evaluating the training programs in the NPCC RCs and BAs. Report on this to the TFCO and RCC– by 9/12.	Attainment of Threshold Goal and: Document methods and processes. Report on this to the TFCO and RCC.– by 12/12	Attainment of Target Goal and: Incorporate into Workshops experiences and lessons learned during NERC audits, specifically related to the NERC standards containing requirements for system operator training, especially COM-002 “Communication and Coordination”, EOP-005 “System Restoration Plans”, EOP-006 “System Restoration Coordination” and EOP-008 “Loss of Control Center Functionality”.– by 12/12

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5.	Situation Awareness – 4%	Threshold	Target	Stretch
a.	Provide outreach to the registered entity to develop viable lessons learned of value to the industry emanating from event analysis or mis-operation data collection to the industry aimed at improving their system reliability and revising/improving reliability standards. Survey the NPCC Members for the value of Lessons Learned produced yearly and report to the RCC.	Develop and post, through the NPCC staff outreach with the registered entity, six Lessons Learned - by 12/12.	Develop and post, through the NPCC staff outreach with the registered entity, six Lessons Learned by 12/12. Conduct follow-up of the NPCC registered entity to determine its implementation - by 12/12.	Expand the NPCC Events Data Base to track to completion the implementation of Lessons Learned and corrective actions identified in the Event Analysis Report and provide an annual report to the RCC - by 12/12.
b.	Ensure the continued cyber reliability of the exchange of telemetry data as the telecommunications industry transitions from the legacy Frame Relay technology to the expanding Multiprotocol Label Switching (MPLS) technology.	Identify the reliability issues which must be addressed in advance of the conversion from Frame Relay to MPLS technology in a white paper to be developed - by 12/12.	Achieve TFIST approval of a white paper identifying the reliability issues which must be addressed in advance of the conversion from Frame Relay to MPLS technology - by 12/12.	Achieve RCC approval of a white paper identifying the reliability issues which must be addressed in advance of the conversion from Frame Relay to MPLS technology and disseminate to the NPCC membership - by 12/12.
6.	**Reliability Assessment & Performance Analysis – 10%**	**Threshold**	**Target**	**Stretch**
a.	Develop NPCC guidelines for load modeling through review of past industry efforts to study dynamic load behavior, and contact others within the industry to benefit from their research. Focus on load behavior during large frequency and voltage excursions and the ability to model when load is tripped. Recommend whether to develop improved models for use in analysis of major disturbances or to develop appropriate models at the time of analyzing a disturbance.	Perform review of current load modeling practices including Zip models and what other regions (WECC, ERCOT, PJM, TransEnergie) have done on load modeling. Document the results of the review and submit report to TFSS and RCC for information – by 8/12.	Attain Threshold, and simulate the effect of the different load models. Perform parametric study on how load models impact inter-area dynamic studies and the impact of modeling step-down transformer. Document results and report them to the TFSS and RCC - by 9/12.	Attain Target, and obtain TFSS and RCC approval of report and recommendations and action plan for Member implementation - by 11/12.

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		Threshold	Target	Stretch
b.	***ERAG/MMWG*** Perform a first contingency (i.e. N-1) thermal analysis (on 100 kV+ facilities) including the use of generation re-dispatch on five ERAG MMWG "off the shelf" power flow cases from the 2011 Series library. The five cases include the 2012 fall, 2012 light load, 2012 shoulder peak, 2013 summer, and 2017 light load. Progress reports to be presented to the RCC/ERAG. This NPCC goal, will lead to improved NPCC model development prior to NERC and FERC submittal, and provides an additional independent quality assessment of the models that are used by NPCC Members as the starting point of their own transmission planning studies.	Complete analysis on all five referenced 2011 ERAG MMWG cases - by 10/12. Provide status reports to RCC /ERAG detailing progress at their 2012 meetings.	Complete analysis on all five referenced 2011 ERAG MMWG cases - by 5/12. Provide status reports detailing progress to the RCC/ERAG at their 2012 meetings.	In addition to the Target Goal, develop and distribute to Members for incorporation into a process document to capture lessons learned, recommendations, and any remedial actions from the results of the referenced 2011 ERAG MMWG quality assessment – by 12/12.
		Threshold	**Target**	**Stretch**
c.	***ERAG-SeRN Semi Annual Joint Study*** Lead and coordinate the inter-regional study analysis of the seasonal NPCC-RFC-SERC East interchange; support the collaboration between the NPCC Members and other SeRN members on running the analysis and preparing the reports to be submitted for acceptance by the ERAG MC. The goal is to disseminate timely approved study results to improve coordinated reliable NPCC seasonal operational and planning.	Oversee the study analysis and preparation of the draft seasonal reports. Obtain approval of the draft reports from the SeRN Steering Committee and for the final report the ERAG Management Committee: Summer Study – by 5/12 Winter Study – by 11/12	In addition to attainment of the Threshold Goal: Provide seasonal reports and summarize key results for use by NPCC RCs in operations and planning areas– by 5/12 Winter Study by 11/12	In addition to attainment of the Completion of the Target Goal: Present key study results for incorporation into Members' seasonal operational analyses to the TFCO, TFSS, TFCP and the RCC. Summer Study by – 6/12, Winter Study by – 11/12
II.	**<u>Cost Effectiveness</u> -** The public and electric utility industry are best served by a well-managed, cost effective Regional Entity who maximizes the utilization of resources in furtherance of reliability.	**Weighting; 20% of Total**		
1.	**Financial – 10%**	**Threshold**	**Target**	**Stretch**
a.	Develop an annual business plan and budget that enables NPCC to fulfill its statutory duties and responsibilities as outlined in the Amended Regional Delegation Agreement and fully exercise its authorities without compromise. Develop a distinct business plan and budget and allocate costs appropriately for regionally-specific criteria services division functions and services among the ISO/BAAs. Manage actual expenses within +/- budget amounts, excluding any significant unanticipated expenses to efficiently accomplish corporate goals and successfully achieve corporate objectives.	Operate within 103% of the initial 2012 Budget as well as applications approved by the Board from operating cash reserves.	Operate within the initial 2012 Budget as well as applications approved by the Board from operating cash reserves	As an overall efficiency goal, operate within 95% of the initial 2012 Budget as well as applications approved by the Board from operating cash reserves.

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2.	**Reliability Standards – 8%**	**Threshold**	**Target**	**Stretch**
a.	Utilize NPCC's Cost Effectiveness Analysis Procedure (CEAP) for a proposed NERC standard to address industry concerns regarding the cost of implementing reliability Standards and the reliability benefit that the Standard will produce.	Pilot the NPCC "Cost Effective Analysis Procedure" on a draft NERC Reliability Standard to gather comments from NPCC stakeholders by 12/12 or on a schedule consistent with NERC drafting team milestones.	In addition to attainment of Threshold, provide CEAP information with the NERC standard drafting team and with NERC Standards Committee (SC) – by 12/12.	In addition to the attainment of Target, develop draft CEAP process for NERC and NERC committees to use and implement as a foundation for a continent wide process – by 12/12
3.	**Human Resources – 2%**	**Threshold**	**Target**	**Stretch**
a.	Place strong emphasis on employee development for the benefit of the individual contributors, the organization, and stakeholders by providing, targeted training on: Technical skills; Management skills; Communication skills; and Team Development.	Establish tracking mechanism to document mentor/mentoree, workshop, seminar, and other training/teaching opportunities afforded to staff	Achieve 80% staff participation in programs provided for and or developed by and shared within staff as developmental training	Achieve 100% staff participation in programs provided for and or developed by and shared within staff as developmental training
III.	**NERC Leadership-** NPCC manages the technical expertise of its staff and Membership resources to maximize their industry-wide value while ensuring that all of NPCC's delegated statutory responsibilities are fulfilled.	**Weighting: 30% of Total**		
1.	**Provide NPCC Policy Input – 10%**	**Threshold**	**Target**	**Stretch**
a.	Within the One Enterprise Model (consisting of NERC and the eight Regional Entities), shape an enhanced reliability assurance structure for North America that is truly international. Provide policy direction to NERC Board of Trustees, NERC senior management, stakeholders, Regional Entity and industry executives. Influence financial policy through the ERO Budget Group to focus NERC on its core functions as a learning organization and continent wide standards development, compliance and reliability assessment. Support common IT solutions across NERC/Regional Entities to defray costs and promote consistency.	Incorporation by NERC of at least 60% of NPCC Board approved policy input.	Incorporation by NERC of at least 75% of NPCC Board approved policy input.	Incorporation by NERC of at least 90% of NPCC Board approved policy input.
2.	**Reliability Standards – 6%**	**Threshold**	**Target**	**Stretch**
a.	NERC Reliability Standards will require Violation Severity Levels (VSLs) and Violation Risk Factors (VRFs) to be developed utilizing new processes; NPCC is currently revising its standards process to develop alternate methods for the development of these VSLs and VRFs. Review posted standards development projects posted for ballot and develop issues and ballot recommendations as appropriate for our members and effectively communicate these issues to our stakeholders.	Provide NPCC, RSC coordinated insights to the NERC Proforma Violation Risk Factor (VRF) and Violation Severity Level (VSL) Projects – by 12/12.	In addition to attainment of Threshold, Develop an NPCC approach to development of VRFs and VSLs in a revised regional standards development processes to reflect changes at NERC. Receive approval and implement new processes – by 12/12.	In addition to attainment of Target, post ballot recommendations or issues papers for at least 90% of NERC Initial Standards Ballot to ensure NPCC members are informed of reliability related issues and implement an electronic blog and post notifications and issues – by 12/12.

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3.	Reliability Assessment & Performance Analysis – 10%	Threshold	Target	Stretch
a.	Support development of NERC Reliability Metrics, including: Consistent Regional reporting of Relay Mis-operations; NPCC Regional support of Transmission Availability Data System (TADS), Generating Availability Data System (GADS), Demand-Response Availability Data System (DADS), & Spare Equipment Database (SED); documenting Underfrequency load shedding operation; operating procedures assumed in conduct of TPL studies; classification and number of Special Protection Systems (SPSs); provide NPCC input to NERC's development of applications and requirements for Special Protection Systems.	Coordinate NPCC Regional entity participation in NERC GADS, DADS, TADS and SEDS web application; provide NPCC Regional responses for data requests to support NERC Reliability Metrics – by 12/12. Provide NPCC direction and input for NERC's development of application and requirements for SPSs - by 12/12.	Attainment of Threshold, provide NPCC direction and input by participation in NERC's GADS, DADS, TADS and SED Working Group meetings – by 12/12. Provide NPCC direction and input for development of Reliability Metrics – by 12/12.	Attainment of Target, achieve 100% NPCC entity participation in NERC GADS, DADS, TADS and SEDS - by 12/12. Provide trending on protection system mis-operations in NPCC; cross check submitted GADS, DADS, TADS data for consistency with related NPCC data – by 12/12.
b.	***Definition of the Bulk Electric System (BES)*** Identify the NPCC electrical facilities consistent with the revised BES definition approved by the NERC BOT and filed at FERC. Develop technical justification required to address the issues identified by the BES Phase 2 SAR.	Collect and analyze information from jurisdictional NPCC entities required to identify NPCC electrical facilities consistent with the revised BES definition – by 12/12 Participate in the NERC BES Phase 2 Drafting Team and related NERC OC/PC activities in 2012 Provide progress reports to the NPCC Board at their 2012 meetings.	In addition to attainment of Threshold, work with jurisdictional NPCC entities to develop a list of BES facilities consistent with the revised BES Definition – by 12/12. Develop consistent recommendations for Regional review of Exception request – by 9/12.	In addition to attainment of Target, review filed BES Exceptions and provide Regional recommendation to NERC – by 12/12.
4.	**Situation Awareness – 4%**			
a.	Coordinate NPCC efforts in support of several NERC initiatives to fulfill the recommendations from the NERC and United States Department of Energy report, "High-Impact, Low-Frequency Event Risk to the North American Bulk Power System." Provide NPCC support for the: Severe Impact Resilience Task Force, Cyber Attack Task Force, Geomagnetic Disturbance Task Force, Spare Equipment Database Task Force, and the Grid Task Force.	Identify needed actions of the five Reliability Coordinators to recommendations of Severe Impact Resilience Task Force, Cyber Attack Task Force, Geomagnetic Disturbance Task Force and the Grid Task Force; - by 12/12	Coordinate response of NPCC RCs to recommendations of Severe Impact Resilience Task Force, Cyber Attack Task Force, Geomagnetic Disturbance Task Force and Grid Task Force - by 12/12	Cite gaps in the NERC and NPCC documentation identified through implementation of recommendations of the HILF Report and formulate NPCC draft language and/or propose SARs. – by 12/12

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Member Representatives Committee (MRC)

February 8, 2012 | 1:00-5:00 p.m. Mountain

Arizona Grand Resort
8000 S. Arizona Grand Parkway
Phoenix, AZ 85044
602-438-9000

Introduction and Remarks from Outgoing MRC Chair

NERC Antitrust Compliance Guidelines and Public Meeting Notice

Consent Agenda – Approve

1. **Minutes**
   a. January 11, 2012 Conference Call
   b. November 2, 2011 Meeting
2. **Future Meetings***

Regular Agenda[1]

3. **Election of Board of Trustees***
4. **Welcome to Phoenix**
5. **Remarks from Gerry Cauley, NERC President and CEO**
6. **Update on ERO Enterprise Strategic Planning and Corporate Goals***
7. **Standards Development Process Improvements***
8. **Rules of Procedure (ROP) Updates** *
9. **Events Analysis Update and Reliability Risk Trends***

[1] Board Chairman John Q. Anderson has invited input from the committee sector representatives on specific agenda items (see attached).

10. **Generator Owners and Operators That Own and Operate Transmission Facilities***

11. **Definition of Adequate Level of Reliability (ALR)***

12. **Bulk Electric System (BES) Definition — Filing of Phase 1 and Preparations for Phase 2***

13. **Geomagnetic Disturbance Task Force (GMDTF) Update***

14. **Compliance Enforcement Initiative (CEI) Update***

15. **Culture of Reliability Excellence***
    a. Eric Ruskamp – Lincoln Electric
    b. Tom Bowe – PJM

16. **November 2011 FERC Technical Conference on Reliability***

17. **Regulatory Update***

*Background materials included.

DRAFT
Electric Reliability Organization Enterprise Strategic Plan 2012-2015

The ERO Enterprise is a collaborative, international network comprised of the North American Electric Reliability Corporation (NERC) and the eight Regional Entities that brings together collective leadership, experience, judgment, skills, and technologies for ensuring the reliability of the North American bulk power system. This plan summarizes the ERO Enterprise's mission, vision, values and goals; and provides strategic direction and priorities for 2012 and beyond, which will be reviewed, revised, and supplemented every other year, if not more frequently.

Mission
To ensure the reliability of the North American bulk power system.

Vision
To be the trusted leadership that ensures and continuously improves the reliability of the North American bulk power system by implementing relevant standards; promoting effective collaboration, cooperation, and communication around important risks to reliability; and utilizing expertise from the industry to produce outcomes that improve reliability.

Core Values and Principles
The following core values and principles serve as guidelines for the conduct and behavior of all involved in the ERO Enterprise.

Accountability and Independence — The ERO Enterprise will:

- Be accountable for the public responsibilities delegated to it (a public trust obligation).
- Be impartial, independent of special interests, and impervious to improper influence.
- Balance its own independent regulatory judgment with the need to involve those with expert knowledge and experience in bulk power system reliability matters.

Responsiveness — The ERO Enterprise will act in a timely manner on the basis of unfolding events, emerging reliability risks, and the needs of industry and other stakeholders.

Fairness and Inclusiveness — The ERO Enterprise will:

- Be open and transparent.
- Provide access for clear communication with stakeholders.

- Ensure the legitimate interests of all parties are duly considered and balanced in the development of policies and reliability standards, and in its programs and operations.
- Conduct compliance and enforcement actions judiciously and in proportion to risk, paying regard to risks both potential and actual (realized).

Adaption and Innovation — The ERO Enterprise will:

- Continuously assess and prioritize its goals.
- Embrace change and encourage new ideas that contribute to effective action.
- Recognize the complex relationships and potential tensions between reliability objectives and business imperatives (including cost control).
- Be nimble and artful in responding to novel, unfamiliar, and emerging challenges.

Excellence —The ERO Enterprise will:

- Promote and rely upon the active participation of the best technical leaders from industry.
- Strive for excellence and efficiency in all aspects of Enterprise activities.

Efficiency —The ERO Enterprise will make informed decisions regarding efficient use of its resources and resources shared by industry.

Integrity — The ERO Enterprise will:

- Maintain the highest levels of professional and ethical conduct.
- Be intellectually honest, truthful, candid, and without bias.
- Be rigorous and thorough in all it does, doing the right things the right way.
- Earn trust by treating every person with fairness and respect.
- Work to meet or exceed expectations of stakeholders.

Four Pillars for Success

In order to succeed, the ERO Enterprise will emphasize:

- ***Reliability*** – to address events and identifiable risks, thereby improving the reliability of the bulk power system.
- ***Assurance*** – to provide assurance to the public, industry, and government for the reliable performance of the bulk power system.
- ***Learning*** – to promote learning and continuous improvement of operations and adapt to lessons learned for improvement of bulk power system reliability.
- ***Risk-based Approach*** – to focus attention, resources and actions on issues most important to bulk power system reliability.

Strategic Goals

These pillars of success support the strategic goals of the ERO Enterprise in the following three major areas of focus:

1. ***Standards and Compliance***
   a) *Develop clear, reasonable and technically sound mandatory reliability standards in a timely and efficient manner.* These standards establish threshold requirements for ensuring the bulk power system is planned, designed, operated, and maintained in a manner that minimizes risks of cascading failures, avoids damage to major equipment, or limits interruptions of bulk power supply.

   b) *Be a strong enforcement authority that is independent, without conflict of interest, objective and fair.* The ERO will retain and refine its ability to use standards enforcement when warranted and impose penalties and sanctions commensurate with risk.

   c) *Promote a culture of compliance with mandatory reliability standards across the industry*. The ERO will support the industry by identifying procedures, practices and controls to address reliability risks resulting from noncompliance.

2. ***Risks to Reliability***
   a) *Identify the most significant risks to reliability*. The ERO will identify and prioritize reliability risks, develop effective solutions and interventions, and monitor results.

   b) *Be accountable for mitigating reliability risks*. The ERO will work with industry stakeholders and experts to ensure the mitigation of known risks to reliability using standards enforcement and other methods where appropriate.

   c) *Promote a culture of reliability excellence.* The ERO will facilitate a learning environment throughout the industry through event causal analysis, communication of lessons learned, tracking of recommendations, and implementation of best practices.

3. ***Coordination and Collaboration***
   a) *Improve transparency, consistency, quality and timeliness of results*. The ERO will accomplish this through effective coordination, collaboration and process improvements.

   b) *Operate as a collaborative enterprise.* The ERO will communicate expectations clearly and foster collaboration to deliver important results in advancing system reliability.

   c) *Improve efficiencies and cost effectiveness*. The ERO will accomplish this by engaging the support of stakeholders, being an efficient steward of resources, and leveraging information systems to create efficiencies and process controls.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Board of Trustees

February 9, 2012 | 8:00 a.m.-12:00 p.m. Moutain

Arizona Grand Resort
8000 S. Arizona Grand Parkway
Phoenix, AZ 85044
602-438-9000

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement

Consent Agenda — Approve

1. **Minutes***
   a. January 18, 2012 Conference Call
   b. November 22, 2011 Conference Call
   c. November 18, 2011 Conference Call
   d. November 3, 2011 Meeting
2. **Election/Membership Appointments and Changes***
   a. Critical Infrastructure Protection Committee Membership
   b. Compliance and Certification Committee Membership

Regular Agenda

3. **President's Report**
4. **Elections**
   a. **Chair-Elect/Vice Chair of Board of Trustees**
   b. **Election and Appointment of Officers**
5. **Board of Trustees Self-Assessment Results*** – **Review**
6. **Electric Reliability Organization Enterprise Strategic Plan 2013-2015** – **Review**
7. **Continent-wide Standard and Interpretations***
   a. Project 2010-07: Generator Requirements at the Transmission Interface – **Approval**
   b. Project 2008-10 Interpretation of CIP-006-1 for Progress Energy – **Approval**
   c. Project 2009-22 Interpretation of COM-002-2 for the IRC – **Consider for Action**

d. Project 2011-INT-01 Interpretation of MOD-028 for Florida Power & Light Company (Rapid Revision standard) – **Approval**

8. **Regional Standard and Standards Development Procedure***
   a. Reliability Standard PRC-006-NPCC-1 – Automatic Underfrequency Load Shedding – **Approval**
   b. SERC Reliability Corporation Regional Standards Development Procedure – **Approval**
9. **NERC Rules of Procedure: Substantive Revisions* – Approval**
10. **Electricity Sector–Information Sharing and Analysis Center (ES-ISAC) Policy Statement* – Approval**
11. **Proposed Amendments to Delegation Agreement with Florida Reliability Coordinating Council (FRCC) – Amended Exhibit B (FRCC Bylaws) and Exhibit D (Compliance Monitoring and Enforcement Program)* – Approval**
12. **Event Analysis Process Document* – Approval**
13. **Status of Action Items from NERC Three-Year ERO Performance Assessment* – Information**
14. **Status of Critical Infrastructure Initiatives* – Information**
15. **Legislative and External Affairs Update* – Information**

Standing Committee Reports* (Item 16)

a. Operating Committee
   1. Status Report
   2. Strategic Plan
b. Planning Committee
c. Critical Infrastructure Protection Committee
d. Member Representatives Committee
e. Personnel Certification Governance Committee
f. Standards Committee
g. Compliance and Certification Committee
   1. Status Report
   2. 2012 Work Plan
   3. 2011 Stakeholder Perception Survey
   4. CCC Spot Check Report of the CMEP
   5. CCC Spot Check of Standards Applicable to NERC
h. Electricity Sub-Sector Coordinating Council

Forum and Group Reports* (Item 17)

a. North American Energy Standards Board

b. Regional Entity Management Group

c. North American Transmission Forum

d. North American Generator Forum

Board Committee Reports*

18. **Corporate Governance and Human Resources**

    a. Review of 2011 Year-end Corporate Performance Goals

    b. Review and Approval of 2012 Corporate Performance Goals

    c. Approval of 2012 Board Committee Assignments

    d. Review of Annual Performance of Company Savings and Investment Plan

19. **Compliance**

20. **Finance and Audit**

    a. Review and Acceptance of Unaudited 2011 Year End Financial Statements

21. **Standards Oversight and Technology**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

John Q. Anderson, Chair
NERC Board of Trustees

January 17, 2012

Mr. Scott Helyer, Chair Elect
NERC Member Representatives Committee
Vice President, Transmission
Tenaska, Inc.
1701 E. Lamar Blvd.
Arlington, Texas 76006

Re: Policy Input to NERC Board of Trustees

Dear Scott:

First, congratulations for being elected to lead the Member Representatives Committee (MRC) in 2012. Bill Gallagher did an outstanding job, so you have a tough act to follow.

After carefully reviewing the agenda for the February 8, 2012 MRC meeting, I would appreciate receiving policy input from the committee members on the following activities, priorities, or other areas of interest:

Update on ERO Enterprise Strategic Planning – Following the November Board of Trustees (Board) meeting, NERC and the Regional Entities rededicated efforts to coordinate a collaborative network, the ERO Enterprise, that brings together their collective leadership, experience, judgment, skills, technology, and duly delegated statutory responsibilities for the purpose of ensuring the reliability of the bulk power system (BPS). As the strategic planning of the ERO Enterprise continues into the New Year, the Board would welcome feedback on how to best identify priority areas of interest, common objectives and responsible business practices. Gerry Cauley will review 2011 performance with the Corporate Governance and Human Resources Committee (CGHRC) at its meeting on February 8, 2012, and plans to present proposed 2012 goals for Board approval at its February 9 meeting. The Board welcomes MRC input on these 2012 goals, as well as longer-term strategic directions for the ERO Enterprise, by way of written policy input as well as open discussion at the MRC meeting on February 8.

Find, Fix, Track, and Report Initiative – NERC and the Regional Entities continue to employ a comprehensive and integrated risk control strategy that differentiates and addresses compliance issues according to their significance to the reliability of the BPS. As NERC and the Regional Entities increase their enforcement discretion in the implementation of compliance and enforcement activities, the Board is interested in hearing the committee members' perspective on the implementation of the Find, Fix, Track, and Report (FFT) process. Your input will also assist NERC in preparation for its six month status report to the Federal Energy Regulatory Commission.

Generator Operator (GO)/Transmission Operator (TO) Issues – NERC has suspended work on the entity registration guidance directive intended to clarify those standards and requirements applicable to GO/GOPs that would be registered as TO/TOPs. NERC will consider the following two outcomes prior to making any further decision to resume work on compliance guidance for the GO/TO initiative:

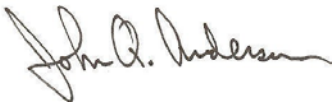
1) Guidance from the Board on the proposed revision of FAC-001, FAC-003 and PRC-004 (Standards Project 2010-07).
2) The final FERC approval of the NERC compliance filing concerning the upheld registry of Cedar Creek and Milford Wind as TO/TOP with appropriately scoped applicable standards.

The Board is particularly interested in policy input on the standards being presented for approval at its February 8 meeting, as well as any comments on the overall issue.

Rules of Procedure Changes — The Board would like to hear of any concerns the committee has with the general direction of the proposed substantive changes to the Rules of Procedure that the Board will consider for approval at its meeting on February 8. Are these changes, to date, effectively addressing the issues raised during previous MRC and Board meetings?

Thank you in advance for providing written comments to Dave Nevius, MRC secretary (dave.nevius@nerc.net) and Holly Mann (holly.mann@nerc.net) **by January 30, 2012** so they can be packaged and sent to the Board members in advance of the meeting.

Thank you,



John Q. Anderson, Chair
NERC Board of Trustees

cc: NERC Board of Trustees
Member Representatives Committee
Regional Executives

NPCC, Inc.

Report by the Treasurer

February 1, 2012

Board of Directors Meeting

NPCC, Inc.

Report Items:

- 2011 Year End Results
- Finance and Audit Committee Activities

NPCC, Inc.

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

January 20, 2012

North American Electric Reliability Corporation
3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
Attention: Mr. Michael Walker

Subject: NPCC Regional Entity Division Variance Comparison and Fourth Quarter 2011 Statement of Activities

Dear Michael:

The variance comparison for the period ended December 31st, 2011 is included along with Northeast Power Coordinating Council, Inc.'s unaudited 4th Quarter 2011 Statement of Activities.

Please do not hesitate to contact me via email at jhala@npcc.org or via telephone at (212) 840-1070 should you have any comments or questions with regard to the materials provided.

Sincerely,

Jessica Hala

Jessica Hala
Senior Financial Analyst

JH: jh
Enclosures

cc: Mr. Christopher Weir, CPA – NPCC Treasurer
Mr. Edward A. Schwerdt – NPCC President & CEO
Ms. Jennifer Budd Mattiello – NPCC Vice President & COO
ERO Finance Group

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

NPCC Regional Entity Division
Budget to Actual
Variance Comparison as of December 31, 2011

INCOME

- **Penalty Sanctions** (Actual income of $308,500 remitted to NPCC as of June 30, 2010 has been applied to reduce 2011 assessments to NPCC U.S. load serving entity designees.) All penalty sanctions remitted from July 1, 2010 through June 30, 2011 will be applied to reduce 2012 assessments to NPCC U.S. load serving entity designees and will be included in the NPCC 2012 Business Plan and Budget.

- **Workshops** (Actual variance of $53k under budget at year end)
  Actual fees charged per person for attending NPCC's standards and compliance workshops were less than originally budgeted.

- **Interest Income** (Actual income of $21k not included in budget)
  NPCC has not budgeted for interest income as returns on U.S. treasury securities fund are non-existent and corporate money market fund returns for 2011 were minimal for operating fund investment.

    - NPCC allocated $21k as a portion of total interest income (92%) to the Regional Entity Division consistent with the ratio of Regional Entity (RE) to Criteria Services (CS) Division 2011 funding. A common system of accounts, with divisional separation, is used for both RE and CS revenue tracking and financial reporting.

EXPENSES

- **Personnel Expenses** (Actual variance of $903k under budget at year end)
    - Recruiting knowledge-based professionals continues to be challenging. NPCC experienced two vacancies during the year from staff departures resulting in unanticipated budget underspend. Additionally, two positions budgeted for the full year in 2011 were not filled until late in the year. As a part of NPCC's succession initiative strategy, several of the 2011 new hires have been less tenured than budgeted for, which also yielded some budget underspend. In the benefits area, a significant number of professionals retained over the past four years continue to waive health insurance coverage, keeping superior coverage available to them from a prior employer. NPCC continues to budget for its full staff's health insurance coverage.

- **Meetings and Conference Calls** (Actual variance of $106k under budget at year end)
    - Continued efforts to hold more meetings onsite or via webinars have kept meeting and conference call expenses under budget. However, travel expenses exceeded budget year-to-date, primarily due to travel associated with compliance audits and on-site Technical Feasibility Exception reviews.

- **Contracts & Consultants** (Actual variance of $729k under budget at year end)
  - NPCC continues to judiciously utilize contractor and consultant services to complement staff functions. In addition, consulting fees associated with website, compliance portal, and software development budgeted under Contracts & Consultants were capitalized in accordance with NPCC capitalization policies and GAAP guidelines.

- **Office Costs** (Actual variance of $128k under budget at year end)
  - Computer equipment and leases budgeted within office costs were capitalized in accordance with NPCC capitalization policies and GAAP guidelines.

- **Miscellaneous** (Actual variance of $19k under budget at year end)
  - Employees training and education expenses were less than budgeted due to scheduling conflicts resulting from workload requirements.

FIXED ASSETS

- **Computer & Software CapEx** (Actual variance of $138k over budget at year end)
  - Acquisition of server software in the third quarter and software development costs in the fourth quarter of 2011.

- **Furniture & Fixtures CapEx** (Actual variance of $21k under budget at year end)
  - NPCC made no furniture & fixtures acquisitions in 2011.

- **Equipment CapEx** (Actual variance of $10k under budget at year end)
  - Actual Equipment Cap Ex of $18k represents acquisition of computer equipment for new employees in 2011.

- **Leasehold Improvements** (Actual variance of $14k under budget at year end)
  - NPCC made no leasehold improvements in 2011.

(Unaudited)
Submitted January 20th, 2012

Northeast Power Coordinating Council, Inc. - Regional Entity Division
Statement of Activities, Fixed Assets and Change in Working Capital
(Unaudited)

	2011 YTD Actual	2011 YTD Budget	2011 YTD Actual Variance from Budget	%
Funding				
Assessments	12,652,610	12,652,610	-	
Penalties	308,500	308,500	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	67,200	120,000	(52,800)	
Interest	20,694	-	20,694	
Miscellaneous	-	-	-	
Total Funding	13,049,004	13,081,110	(32,106)	-0.25%
Expenses				
Personnel Expenses				
Salaries	4,361,224	5,055,070	(693,846)	
Payroll Taxes	277,841	291,508	(13,667)	
Employee Benefits	973,785	1,134,918	(161,133)	
Savings & Retirement	791,099	825,301	(34,202)	
Total Personnel Expenses	6,403,949	7,306,797	(902,848)	-12.36%
Meeting Expenses				
Meetings	215,520	269,325	(53,805)	
Travel	872,965	668,000	204,965	
Conference Calls	51,729	96,571	(44,842)	
Total Meeting Expenses	1,140,214	1,033,896	106,318	10.28%
Operating Expenses				
Consultants and Contracts	1,526,367	2,255,047	(728,680)	
Rent & Improvements	621,276	626,127	(4,851)	
Office Costs	355,346	483,434	(128,088)	
Professional Services	880,336	892,751	(12,415)	
Miscellaneous	37,074	55,450	(18,376)	
Depreciation	180,799	138,626	42,173	
Total Operating Expenses	3,601,198	4,451,435	(850,237)	-19.10%
Other Non-Operating Expenses	-	-	-	n/a
Total Expenses	11,145,361	12,792,128	(1,646,767)	-12.87%
Net Change in Assets	**1,903,643**	**288,982**	**1,614,661**	**558.74%**
Fixed Assets				
Depreciation	(180,799)	(138,626)	(42,173)	
Computer & Software CapEx	138,341	-	138,341	
Furniture & Fixtures CapEx	-	20,886	(20,886)	
Equipment CapEx	18,549	28,557	(10,008)	
Leasehold Improvements	-	13,863	(13,863)	
Incr(Dec) in Fixed Assets	**(23,909)**	**(75,320)**	**51,411**	**-68.26%**
Total Budget (Expenses plus Incr(Dec) in Fixed Assets)	**11,121,452**	**12,716,808**	**(1,595,356)**	**-12.55%**
Change in Working Capital (Total Funding less Total	**1,927,552**	**364,302**	**1,563,250**	**429.11%**
Full Time Employees	31.42	31.42	-	
Headcount	32.00	32.00	-	
Beginning WC - 1/1/11	3,664,561	3,664,561	-	
Change to WC - 2011	1,927,552	364,302	1,563,250	
Working Capital at 12/31/11	**5,592,113**	**4,028,863**	**1,563,250**	

Via E-mail

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

January 25, 2012

Full and General Member Representatives
and
NPCC Board of Directors

Ladies and Gentlemen:

Attached for your information are copies of the Northeast Power Coordinating Council, Inc.'s Regional Entity and Criteria Services divisions' unaudited statements of activities for the year ended December 31, 2011. NPCC's Regional Entity division actual total expenses for 2011 were $11,145,359 which is $1,646,770 or approximately 13% under the 2011 Regional Entity division budget of $12,792,129. NPCC's Criteria Services division actual total expenses for 2011 were $859,764 which is $160,707 or approximately 16% under the 2011 Criteria Services division budget of $1,020,471.

Under budget total expenditures for much of the North American reliability corporations can be largely attributed to recruitment and retention challenges that are being faced by these companies whose workload continues to expand.

Very truly yours,

Jennifer Budd Mattiello

Jennifer Budd Mattiello
Vice President & COO

JBM: jh
Enclosure

(In Whole Numbers)

Account Code	Account Title	Regional Entity Budget Amount	Regional Entity Actual Amount	Criteria Services Budget Amount	Criteria Services Actual Amount	Total NPCC Actual Amount
Revenue						
NERC (ERO) Funding						
41000	Assessments	$ 12,652,610	$ 12,652,610	$ -	$ -	$ 12,652,610
41100	Penalty Sanctions	308,500	308,500	0	0	308,500
Total NERC (ERO) Funding		12,961,110	12,961,110	0	0	12,961,110
ISO/BAA Funding						
42000	Membership Dues	0	0	349,600	349,600	349,600
Total ISO/BAA Funding		0	0	349,600	349,600	349,600
Workshops						
47000	Workshops	120,000	67,200	0	0	67,200
Total Workshops		120,000	67,200	0	0	67,200
Interest Income						
49000	Interest Income	0	20,694	0	2,299	22,993
Total Interest Income		0	20,694	0	2,299	22,993
Total Revenue		**$ 13,081,110**	**$ 13,049,004**	**$ 349,600**	**$ 351,899**	**$ 13,400,903**
Expenditures						
Salaries						
51000	Direct Salaries	$ 5,018,103	$ 4,337,065	$ 346,040	$ 374,523	$ 4,711,588
51200	Employment Agency Fee	27,725	18,598	2,275	(104)	18,495
51300	Temporary Office Services	9,242	5,561	758	0	5,561
Total Salaries		5,055,070	4,361,224	349,073	374,419	4,735,644
Payroll Taxes						
52000	Payroll Taxes-FICA	208,157	191,500	16,368	15,648	207,149
52100	Payroll Taxes-Medicare	70,514	61,102	4,804	5,028	66,130
52200	Payroll Taxes-SUI	10,417	8,059	854	708	8,767
52300	Payroll Taxes-FUI	2,420	1,836	198	161	1,997
52400	Payroll Taxes-MCTMT	0	15,343	0	1,268	16,610
Total Payroll Taxes		291,508	277,840	22,224	22,813	300,653
Benefits						
54000	Benefits-Education Reimbursement	9,519	54,626	781	0	54,625
54001	Benefits-Training Classes and Seminars	702,468	0	58,044	0	0
54100	Benefits-Medical	45,787	548,486	26,813	17,050	565,537
54200	Benefits-Life	0	44,645	0	29,554	74,198
54250	Officers - Life	14,156	8,571	1,162	319	8,891
54300	Insurance -WC	362,988	(934)	24,989	(81)	(1,015)
54400	Vacation Expense	0	318,391	0	27,501	345,892
Total Benefits		1,134,918	973,785	111,788	74,343	1,048,128
Retirement						
55000	Pension Contribution	485,190	519,077	114,810	80,923	600,000
55100	Employee Savings Plan	306,493	247,552	27,191	21,006	268,558
55200	Pension & Savings Admin	8,824	4,700	724	400	5,100
55300	Deferred Compensation Exp	24,794	19,770	1,706	1,330	21,100
Total Retirement		825,301	791,099	144,431	103,659	894,758
Meetings Expenses						
61000	Meeting Expense	121,600	156,901	7,000	23,347	180,247
61100	Workshop Exp	147,725	58,620	2,275	25	58,645
Total Meetings Expenses		269,325	215,521	9,275	23,372	238,892
Travel Expenses						
62000	Travel	668,000	872,965	69,000	39,577	912,542
Total Travel Expenses		668,000	872,965	69,000	39,577	912,542

(In Whole Numbers)

Account Code	Account Title	Regional Entity Budget Amount	Regional Entity Actual Amount	Criteria Services Budget Amount	Criteria Services Actual Amount	Total NPCC Actual Amount
Communications						
63000	Conference Calls	95,200	51,729	9,000	4,342	56,071
63100	Online Meetings	1,371	0	130	0	0
Total Communications		96,571	51,729	9,130	4,342	56,071
Contracts & Consultants						
65000	Consultants	169,510	78,379	12,090	2,671	81,050
65100	Contracts	2,085,537	1,447,988	113,250	34,176	1,482,164
65400	Industry Support	0	0	0	0	0
Total Contracts & Consultants		2,255,047	1,526,367	125,340	36,847	1,563,214
Office Rent						
70000	Office Rent	582,229	578,693	47,771	49,690	628,383
70010	Utilities	23,104	25,913	1,896	2,245	28,158
70020	Maintenance	18,483	14,459	1,517	1,259	15,718
70030	Security	2,310	2,210	190	195	2,406
Total Office Rent		626,127	621,275	51,373	53,389	674,665
Office Costs						
71000	Telephone	138,626	139,685	11,374	11,774	151,459
71100	Internet Expense	32,346	13,616	2,654	549	14,164
71200	Office Supplies	25,877	23,291	2,123	1,777	25,068
71300	Computer Supplies & Maintenance	36,967	37,971	3,033	3,256	41,226
71400	Subscriptions & Publications	6,469	8,429	531	539	8,968
71500	Dues	3,697	1,885	303	0	1,885
71600	Postage	1,479	628	121	63	692
71700	Express Shipping	6,469	8,170	531	662	8,832
71800	Copying	1,848	519	152	0	519
71900	Reports	5,545	4,162	455	354	4,516
72000	Stationary & Office Forms	5,545	2,013	455	157	2,170
72100	Equipment Repair/Srv. Contracts	41,588	3,880	3,412	337	4,217
72200	Bank Charges	36,967	13,286	3,033	1,475	14,761
72500	Presentation and Publicity	4,621		379		
Total Office Costs		348,043	257,535	28,557	20,943	278,477
Professional Services						
75000	BOT Fee	184,835	125,609	15,165	10,891	136,500
75100	BOT Search fee	0	134,182	0	11,748	145,930
75200	Legal - Reorganization	0	0	0	0	0
75300	Accounting and Auditing Fees	221,801	260,525	18,199	21,985	282,510
75400	Legal Fees - Other	462,086	334,669	37,914	28,644	363,313
75500	Insurance - Commercial	24,028	25,351	1,972	2,392	27,743
Total Professional Services		892,751	880,336	73,249	75,660	955,996
Capital Expenditures						
90100	Furniture Purchase		0		0	0
90300	Computer Purchase and Lease	135,391	97,810	11,109	8,543	106,354
Total Capital Expenditures		135,391	97,810	11,109	8,543	106,354
Depreciation Expense						
95100	Depreciation Expense-Equipment	138,626	71,606	11,374	7,955	79,561
95250	Depreciation - Software	0	30,726	0	3,145	33,870
95300	Depreciation Expenses-Furniture	0	18,142	0	2,011	20,153
95400	Depreciation Expense - L.I.	0	60,325	0	6,703	67,028
Total Depreciation Expense		138,626	180,799	11,374	19,814	200,612
Miscellaneous Expenses						
99000	Miscellaneous Expense	55,450	37,074	4,550	2,043	39,116
Total Miscellaneous Expenses		55,450	37,074	4,550	2,043	39,116
Total Expenditures		**12,792,129**	**11,145,359**	**1,020,471**	**859,764**	**12,005,122**
Change in Assets		**288,981**	**1,903,645**	**(670,871)**	**(507,865)**	**1,395,781**

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. PA12-10-000
October 28, 2011

Northeast Power Coordinating Council, Inc.
Attention: Mr. Edward A. Schwerdt
President and Chief Executive Officer
1040 Avenue of the Americas, 10th Floor
New York, NY 10018

Dear Mr. Schwerdt:

The Division of Audits (DA) in the Office of Enforcement (OE) of the Federal Energy Regulatory Commission (the Commission) is commencing an audit of the Northeast Power Coordinating Council (NPCC). This audit will address NPCC's responsibilities and performance as a Regional Entity, including its performance pursuant to (1) the Delegation Agreement between the North American Electric Reliability Corporation and NPCC, (2) the NPCC Bylaws, and (3) other obligations and responsibilities as approved by the Commission. Additionally, the audit will evaluate NPCC's budget formulation, administration, execution, and resources used to achieve program results. This audit will cover the period from August 23, 2006 to the present.

This audit is being conducted pursuant to section 215 of the Federal Power Act, 16 U.S.C. § 824o (2006). Documents and information obtained by the Commission staff during the audit, as well as all working papers developed, will be placed in non-public files. Section 39.2(d) of the Commission's regulations, 18 CFR § 39.2(d) (2011), provides that each Regional Entity shall provide the Commission such information as is necessary to implement section 215 of the Federal Power Act.

NPCC must preserve and retain all existing and future records relevant to this audit. For purposes of this compliance audit, OE considers all relevant records to be all documents and communications (including emails, instant messages, text messages, and voice recordings) which are in the possession, custody or control of NPCC and its affiliates and either: (1) are used in preparation of responses to the attached data requests; (2) relate to any service provided or to be provided by, on behalf of, or for the benefit of NPCC and its affiliates or any facility owned or operated by, on behalf of, or for the benefit of the Company and its affiliates; (3) are communications, transactions, agreements or arrangements between NPCC and any of its affiliates, or between any

director, officer, manager, or other employee of the Company, and any director, officer, manager, or other employee of the Company's affiliates; or (4) relate to the subject matter of any data requests made to NPCC in this audit.

We will contact you shortly to schedule an entrance conference to discuss the nature of the audit engagement. The purposes of the conference call are to: (1) explain the audit process to NPCC; (2) address any questions about the audit that NPCC may have; (3) provide the audit team an opportunity to clarify basic information about NPCC; and (4) discuss the initial data request. If you have any questions concerning this letter, please contact Ms. Adina Mineo, Auditor-in-Charge at (202) 502-6255.

In addition, if you would like to discuss the audit with DA management at any time during the course of this audit, please contact Ms. Teresina Stasko, Branch Chief, at (202) 502-8317, or Mr. Bryan Craig, the Director of the Division of Audits and Chief Accountant, at (202) 502-8741.

Sincerely,

Norman C. Bay
Director
Office of Enforcement

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. PA12-10-000
December 14, 2011

Northeast Power Coordinating Council, Inc.
Attention: Mr. Edward A. Schwerdt
President and Chief Executive Officer
1040 Avenue of the Americas, 10th Floor
New York, NY 10018

RE: Data Request No. 1

Dear Mr. Schwerdt,

By letter dated October 28, 2011 the Office of Enforcement of the Federal Energy Regulatory Commission commenced an audit of Northeast Power Coordinating Council (NPCC).

Attached is Data Request No. 1 (Attachment A) to facilitate our review. Also attached are the General Instructions and Definitions (Attachment B) that govern this data request and all subsequent data requests, should any be required.

Please submit your responses on a rolling basis, with the first set due no later then January 13, 2012, to:

Federal Energy Regulatory Commission
Division of Audits
Attention: Adina Mineo, Rm 51-51
888 First Street, N.E.,
Washington D.C. 20426.

If you have any questions about the data request, please contact Ms. Adina Mineo at (202) 502-6255, or by email at adina.mineo@ferc.gov. If the company cannot provide responses to all of the data requests by the required date, please contact Ms. Mineo at the earliest possible time to discuss the reason for the delay and propose an alternative time table to accommodate the company's needs. The company should, regardless of an inability to provide some responses, provide all responses it can by the deadline above.

This audit is being conducted pursuant to section 215 of the Federal Power Act, 16 U.S.C. § 824o (2006). Documents and information obtained by the Commission staff during the audit, as well as all working papers developed, will be placed in non-public files. Section 39.2(d) of the Commission's regulations, 18 CFR § 39.2(d) (2011), provides that each Regional Entity shall provide the Commission such information as is necessary to implement section 215 of the Federal Power Act.

Sincerely,

Bryan K. Craig
Director and Chief Accountant
Division of Audits
Office of Enforcement

Attachment A - Data Request No. 1
Attachment B - General Definitions and Instructions

From:	Maritza Feliciano
To:	npcc-bod-2012
Cc:	grpStaff
Subject:	BOD Agenda Package for 2-1-12 Meeting
Date:	Monday, January 30, 2012 5:05:39 PM
Attachments:	Agenda Package for NPCC BOD Meeting 2-1-12.pdf
Importance:	High



NPCC Board of Directors

Dear Directors,

This email is being provided on behalf of NPCC's President and CEO, Edward A. Schwerdt and serves as the third mail out of agenda materials for the NPCC Board of Directors Meeting to be held on Wednesday, February 1, 2012 from 8:00 AM until approximately Noon.

The attached agenda package can be used as a replacement for that received last week. Agendas for the NERC Member Representatives Committee and Board of Trustees meetings which will be held next week are now included with the NPCC Board package. However in as much as the bulk (over 700 pages of the 880 pages total) of the NERC materials were not available until 1:55 AM this morning, January 30th, a draft of the Board's policy input will be available tomorrow around the table and will be distributed electronically before the start of the Strategy Session for those attending telephonically.

The revised NPCC Agenda Package for the Board of Directors Meeting has been posted on the BOD FTP Secure Site.

The URL address to download this agenda package is https://neptune.npcc.org/thinclient.

The User ID is npccbod and the

Password is BO@rd12.

The dial-in information for those unable to attend the meeting in person is as follows:

1-877-260-3999 Participant Code 6945#

Please feel free to contact me if you have any questions.

Sincerely,

Maritza Feliciano
Office Manager and Executive Assistant
Northeast Power Coordinating Council, Inc.
☎ (212) 840-1070
🖷 (212) 302-2782
mfeliciano@npcc.org

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Background Information

For Quality Reviews

January 7, 2012

RELIABILITY | ACCOUNTABILITY






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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Introduction

Purpose

Each reliability standard must have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system. The purpose statement should identify the reliability-related benefit of the standard and should be tied to at least one of the reliability principles.

The set of requirements in the standard should collectively support the purpose statement.

Applicability Section of the Standard

The applicability section of the standard should identify all of the functional entities assigned responsibility for one or more requirements in the standard. While standard drafting teams should use the same terminology for identifying responsible entities as used in the compliance registry, the compliance program may authorize deviations where needed for reliability.

The applicability section should also include any limitations on the applicability of the standard based on electric facility characteristics, such as a requirement that applies only to the subset of distribution providers that own or operate underfrequency load shedding systems.

The applicability section should also identify situations where one or more requirements apply to just a subset of the bulk power system such as requirements that apply only to Transmission Lines rated at 200kV or higher.

This section may also identify specific conditions under which one or more requirements may or may not apply.

Requirements

Each reliability standard must include one or more requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest.

Each requirement must establish an objective that is the best approach for bulk power system reliability, considering the costs and benefits of implementing the proposal. Each requirement must be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement. Requirements should have the following characteristics:

- Each requirement must identify what functional entity shall do what, under what special conditions (if any), for what reliability benefit.
- Each requirement should be aimed at achieving one objective and written in the 'active' voice.
- If specific results can be practically measured quantitatively, metrics should be provided within the requirement to indicate satisfactory performance.
- To the maximum extent possible the requirement must be designed to apply throughout the interconnected North American Bulk-Power System.

Reliability standards should not contain:

- Requirements that prescribe commercial business practices which do not contribute directly to reliability.
- Reliability standards should not contain requirements that duplicate or conflict with one another.

Requirements referencing an attachment:

- If a requirement references an attachment (such as a requirement that says, "in accordance with attachment x") then that attachment is an extension of the requirement, and should be reviewed as such.

Measures and Evidence Retention

Measures

Each requirement must have one or more associated measures used to objectively evaluate compliance with the requirement. A single measure may be used to address more than one requirement. Each measure must identify the functional entity with the performance being measured – the same functional entity that is responsible for the associated requirement. Each measure must be tangible, practical, and as objective as is practical. Measures should support requirements by identifying what evidence or types of evidence could be used to show that an entity is compliant with the requirement. For some requirements, only one type of evidence is acceptable – but for many requirements, a range of evidence could be acceptable. The following is a synopsis of the guidelines provided to drafting teams:

- If the requirement is to have a document such as an agreement, methodology, or procedure, then the measure should require the responsible entity to provide that document – and if the requirement has timing-related aspects such "current" or "updated" then the evidence must include references to dates.
- If the requirement is to verify something, then the measure should include the criteria for verification (if applicable) as well as the evidence to support that the verification was conducted – and if the verification is required to be executed on some periodic basis, then the evidence must include references to dates.
- If the requirements is to "do" something such as perform maintenance, communicate information, provide data – then the measure must include evidence that the action was performed – and if the action is required under specified conditions or with some specified frequency, then evidence of the conditions under which the action was performed as well as a reference to the time when the action was performed should be included in the measure.
- Attestations are acceptable. An attestation has to be made by an individual, not just on behalf of an entity. This put an individual's character on the line, and tends to make people be more truthful. If it turns out to be false, that is considered in the determination of the penalty for the entity.

Evidence Retention

On January 1, 2011 the Rules of Procedure Appendix 4c – Section 3.1.4.2 that became effective Jan 1, 2011 included the following:

> 3.1.4.2 Period Covered
>
> The Registered Entity's data and information should show compliance with the Reliability Standards that are the subject of the Compliance Audit for the period beginning with the day after the prior audit by the Compliance Enforcement Authority ended (or the later of June 18, 2007 or the Registered Entity's date of registration if the Registered Entity has not previously been subject to a Compliance Audit), and ending with the End Date for the Compliance Audit. However, if another Compliance Monitoring and Enforcement process has been conducted with respect to the Registered Entity subsequent to the date that would otherwise be the start of the period, the period covered by the Compliance Audit may, in the Regional Entity's discretion, begin with the completion of that Compliance Monitoring and Enforcement process for those Reliability Standards requirements that were the subject of the Compliance Monitoring and Enforcement process. The End Date will be stated in the Compliance Enforcement Authority's notification of the Compliance Audit issued to the Registered Entity pursuant to Section 3.1.1. The Registered Entity will be expected to demonstrate compliance for the entire period described above. However, if a Reliability Standard specifies a document retention period that does not cover the entire period described above, the Registered Entity will not be found in noncompliance solely on the basis of the lack of specific information that has rightfully not been retained based on the retention period specified in the Reliability Standard. However, in such cases, the Compliance Enforcement Authority will require the Registered Entity to demonstrate compliance through other means.

To ensure that responsible entities understand the above, drafting teams have been advised to include the following paragraph as the first paragraph in the Evidence Retention section of the standard.

> 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.

There are two types of evidence that must be kept – evidence used by entities to show that they are compliant with the requirements and evidence retained by the CEA to verify that it has assessed compliance. The measures should serve as a guide in identifying which responsible entity must keep what evidence for how long.

For the "Data/Evidence Retention" section of the standard, the following default language is recommended for identification of retention periods – with variations to the sentence structure as needed:

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 [responsible entity] shall retain evidence of Requirement 1, Measure 1 for [Insert Time Period].

If a [responsible entity] is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

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

The following tables were extracted from the latest approved version of "Drafting Team Guidelines"

http://www.nerc.com/files/NERC_Drafting_Team_Guidelines_Endorsed_by_SC_April2009.pdf

Agreements, Training, Records, Procedures, Processes, Plans, Methodologies, Models		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Have an agreement	Dated document with confirmation of agreement Dated electronic communications with confirmation of agreement	Current, in force agreement and agreements in force since last compliance audit period.
Document authority	Dated job description that includes statement of authority with respect to other operating entities Dated letter declaring authority signed by an authorized and appropriate corporate officer Dated department notice signed on corporate letterhead Dated Agreement with authority documented	Current, in force document and any documents in force since last compliance audit period.
Have a set of requirements, process, plan, procedure, methodology, or other document– no requirement to update	Dated, current, in force document with specified elements	Current, in force document and any documents in force since last compliance audit period.
Have a set of requirements, process, plan, procedure, methodology, or other document–requirement to update	Dated, current, in force document with specified elements and evidence of last issue	Current and previous 3 years' versions Current, in force document plus the 'date change page' from each version issued since the last audit or the current and previous version All versions from prior 3 years

Agreements, Training, Records, Procedures, Processes, Plans, Methodologies, Models		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Have a specific record with no mention of update	Dated, specified record in electronic or hard copy format	Current, in-force and at least one previous period
Have specific operational plan (real-time, next day, seasonal) with specified elements	Dated, actual plan with specified elements	Rolling 6 months or previous document, whichever is longer.
Have a model	Model	Latest version and evidence of the previous version.

Verifications		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Verify personnel qualifications	Dated certification records Training records showing successful completion with description of training activity and employee name, date Supervisor check sheets showing employee name, date performance noted Records showing mastery or completion with employee name, date	Latest verification of each qualification records for rolling 6 months
Verify facility meets specified criteria	Dated demonstration that facility meets criteria Dated Equipment specification showing facility meets criteria Dated installation documentation showing	Current and previous set of evidence if updated since previous compliance audit

Verifications		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
	that facility meets criteria Dated test results to show that facility meets criteria Dated computer output to show that facility meets criteria	
Verify accuracy of data	Verification process and results with date verified	Latest and prior verification
Verify accuracy of data – requirement to update on a specified periodicity	Verification process and results with date verified	Latest and prior
Verify specific training occurred– no minimum hour requirement	Actual training program materials or description with dated completion records for employees	3 calendar years
Verify specific training occurred– minimum hour requirement	Actual training program materials or description with dated completion records for employees and # of course hours	3 calendar years
Verify staff has proper certification	Staffing plan Certification numbers for personnel in staffing plan	Current plus previous year

Perform, Implement, Execute, Develop, Maintain		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Perform a mathematical calculation via	Dated data to support the calculation	Unless otherwise specified in the standard:

Perform, Implement, Execute, Develop, Maintain		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
computer and report results on a periodic basis	retained in an electronic format Dated hard copy of output of mathematical calculation plus documented formula and input Dated copies of periodic reports	For calculations done on a continuous basis (e.g. hourly, daily, and up to weekly) – most recent 3 calendar months For calculations done on a monthly basis – 1 calendar year For calculations done on a periodicity longer than monthly – 3 calendar years
Implement follow up plan	Follow up plan that includes timetable for implementation with check sheet to show date each milestone achieved	12 months after implementation plan completed
Perform maintenance in accordance with schedule	Schedule plus maintenance records showing date and what was done	3 calendar years
Perform testing or simulation in accordance with schedule	Schedule plus test records (or simulation records) showing date of test, type of test, what was tested, test procedure, test results	3 calendar years
Conduct an assessment (impact of connecting new facilities; effectiveness of SPS; SPS operations; long-range plan)	Results of assessment with assumptions, contingencies, models used	6 calendar years
Perform an analysis of an event with a follow up plan (mitigation plan, corrective action plan)	Analysis report and follow up plan that includes time table for implementation	12 months after implementation plan completed
Have and follow a maintenance, testing, or other program (vegetation management)	Paper or electronic copy of program with schedule and records showing what was done to implement the program with dates and activities accomplished	3 calendar years

Perform, Implement, Execute, Develop, Maintain		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Develop ratings or limits according to methodology	Methodology accompanied by ratings or limits Demonstrate limits developed according to methodology	12 months or previous limits and methodology whichever is longer.
Maintain specified data	Database with specified data List in hard copy or electronic format with specified data	Latest version and evidence of a previous version.

Operate, Request, Communicate		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Operate within defined parameters	Dated parameters and report of any event with operation outside defined parameters including date, time, duration, details of how far outside parameters	Exception reports – 3 calendar years *(Under 'Additional Compliance Information' - Submit report of exceedances (use proper name of report) to CEA within 30 days of the initiation of the event*
Respond to reliability-related concerns	Paper or electronic notice of response showing date, name and title of responder and any action to be taken in response to reliability-related concern with	Notices and responses – 3 calendar years *(Under 'Additional Compliance Information' - Copy of concern and within 30 days of receipt/response)*
Request data or information	Dated paper or electronic notice used to request data showing data, recipient, and	Latest issued

Operate, Request, Communicate		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
	data or information requested	
Communicate operating information (requirements to notify, direct, inform, or communicate operating information to others who need the information to take action)	Dated operator Logs	Most recent 12 months
	Voice recordings or transcripts of voice recordings	Most recent 3 months

Report, Provide Data or Information		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Distribute or make a set of limits, procedure, process, plan, report or other prepared document available to others	Email notice with updated web page Postal receipt showing recipient, date, contents Demonstration of public posting (if not required to distribute to specific people)	1 calendar year for items that are updated at least monthly 3 calendar years for items that are updated less than once a month
Post information on web and ensure entities know of updated information	Link to web page and either a copy of the electronic notice sent to advise recipients of the posting or a postal receipt showing recipient, date and contents	90 calendar days
Post updated information on web	Link to web page	90 calendar days
Submit operating data or information as requested and according to schedule	Request for data with schedule accompanied by copy of transmittal notice including identification of data submitted, date	90 calendar days

Report, Provide Data or Information		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
	submitted	
Submit planning data or information as requested and according to schedule	Request for data with schedule accompanied by copy of transmittal notice including identification of data submitted, date submitted	1 calendar year or the last planning cycle whichever is longer.
Submit data related to a disturbance or event	Request for data with transmittal notice including identification of data submitted, date submitted	3 calendar years or for the duration of any regional investigation, whichever is longer. (This should be a long time as there may be a need to investigate further if a similar event occurs.)

Compliance Elements Used to Administer Compliance

Compliance Enforcement Authority

For most standards, the compliance enforcement authority will be the 'Regional Entity' and this is what should be entered. If the Regional Entity is the responsible entity or the responsible entity works for the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity) to be responsible for compliance enforcement.

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority 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.

For NERC, a third-party monitor without vested interest in the outcome for NERC shall serve as the Compliance Enforcement Authority.

Compliance Monitoring and Assessment Processes

This section identifies the processes that may be used by the CEA to monitor compliance with the requirements in the standard. There are eight processes defined in the Uniform Compliance Monitoring and Enforcement Program (CMEP) of the North American Electric Reliability Corporation, and for most standards, the first six of the eight processes listed below are applicable. The last two processes (Periodic Data Submittals and Exception Reporting) are only applicable in certain standards. With the exceptions noted for periodic data submittals and exception reporting, drafting teams should not add descriptive language to identify "how" a process will be implemented as the CMEP includes details on the implementation of each of these processes.

1. Compliance Audit
2. Self-Certification
3. Spot Checking
4. Compliance Investigation
5. Self-Reporting
6. Complaint
7. Periodic Data Submittals – If periodic data submittal is listed, the submittal interval must be specified. The details should be included in the "Additional Compliance Information" section of the standard.
8. Exception Reporting – If exception reporting is listed, the conditions for the report must be specified. The details should be included in the "Additional Compliance Information" section of the standard.

Compliance Elements Used to Assist in Assigning Penalties and Sanctions

Time horizons, Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are used as a factor in determining the size of a penalty or sanction for noncompliance with the requirement.

Time Horizons

Each requirement must have an associated Time Horizon to identify the time frame an entity would have to correct a violation of the requirement. The Time Horizons and the criteria for each include:

- Long-term Planning — a planning horizon of one year or longer.
- Operations Planning — operating and resource plans from day-ahead up to and including seasonal.
- Same-day Operations — routine actions required within the timeframe of a day, but not real-time.
- Real-time Operations — actions required within one hour or less to preserve the reliability of the bulk electric system.
- Operations Assessment — follow-up evaluations and reporting of real time operations.

Violation Risk Factors

Each requirement must have an associated violation risk factor (High, Medium or Lower). The risk factor assesses the impact to reliability of violating a specific requirement. The following criteria have been filed with FERC as part of the ERO's Sanctions Guidelines and must be used to determine a violation risk factor for each requirement:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the

preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

In addition, in its May 18, 2007 Order on Violation Risk Factors, FERC identified five "guidelines" it uses to determine whether to approve the Violation Risk Factors submitted for approval. Those factors are:

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

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. From footnote 15 of the May 18, 2007 Order, FERC's list of critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System includes:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

In addition, NERC established the following detailed guidelines for setting VSLs:

1. If the requirement is binary, or when any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement, then the single VSL must be "Severe". (This is not the same as saying that the requirement is really important and any noncompliance would have an adverse reliability impact – the impact to reliability should be addressed through the VRF, not the VSL.)

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
EOP-002 R3.	N/A	N/A	N/A	The Balancing Authority experienced an operating capacity or energy emergency and failed to communicate its current and future system conditions to its Reliability Coordinator and its neighboring Balancing

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Authorities.
EOP-005 R8.	N/A	N/A	N/A	The Transmission Operator resynchronized without approval of the Reliability Coordinator or not in accordance with the established procedures of the Reliability Coordinator following a Disturbance in which Blackstart Resources were required for restoring the shut down area of the BES to service.

2. If the requirement has a wide range of possible noncompliant performance the requirement should have multiple VSLs.

   There are many different ways of developing VSLs to categorize different degrees of noncompliant performance. The set of VSLs developed should collectively address all of the elements in the requirement. Thus, if a requirement includes both specific actions and a timeframe for completion of those actions, then the VSLs should address noncompliance with both the completeness of the actions and the timeliness of those actions. Not all VSLs need to address both components of the requirement, but collectively the set of VSLs must address all aspects of the requirement.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-009 R2.	The responsible entity that owns or operates a UFLS program (as required by its Regional Reliability	The responsible entity that owns or operates a UFLS program (as required by its Regional Reliability	The responsible entity that owns or operates a UFLS program (as required by its Regional Reliability	The responsible entity that owns or operates a UFLS program (as required by its Regional Reliability

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Organization) provided its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database but its annual update was late by 30 calendar days or less.	Organization) provided its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database but its annual update was late by more than 30 calendar days but less than or equal to 40 calendar days.	Organization) provided its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database but its annual update was late by more than 40 calendar days but less than or equal to 50 calendar days.	Organization) did not provided its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database, OR The responsible entity's annual update was late by more than 50 calendar days.

3. If the requirement has multiple parts that contribute unequally to the reliability-related intent of the requirement, each numbered part of the requirement should be identified separately in the VSLs.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
EOP-001 R7.	The responsible entity demonstrated that it coordinated its emergency plans with other Transmission Operators and Balancing Authorities as appropriate but the coordination specified in R7, Part 7.4 was applicable and was not	The responsible entity demonstrated that it coordinated its emergency plans with other Transmission Operators and Balancing Authorities as appropriate but the coordination specified in R7, Part 7.3 was applicable and was not	The responsible entity demonstrated that it coordinated its emergency plans with other Transmission Operators and Balancing Authorities as appropriate but the coordination specified in either R7, Part 7.1 or in R7, Part 7.2 was	The responsible entity demonstrated that it coordinated its emergency plans with other Transmission Operators and Balancing Authorities as appropriate but the coordination specified in two (2) or more of the four (4) Parts of

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
	included.	included.	applicable and was not included.	Requirement R7 were applicable and were not included.

4. If the requirement has multiple parts that contribute equally to the reliability-related intent of the requirement, the VSLs should be set based on the number of parts that are noncompliant or a percentage of noncompliant performance without regard to which part is "missing" or noncompliant.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-009 R1.	The responsible entity that owns or operates a UFLS program failed to include **one** of the elements listed in PRC-009-0 Requirement R1, Parts 1.1 through 1.4 in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.	The responsible entity that owns or operates a UFLS program failed to include **two** of the elements listed in PRC-009-0 Requirement R1, Parts 1.1 through 1.4 in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.	The responsible entity that owns or operates a UFLS program failed to include **three** of the elements listed in PRC-009-0 Requirement R1, Parts 1.1 through 1.4 in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.	The responsible entity that owns or operates a UFLS program failed to conduct an analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 Requirement R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.

5. If noncompliance is measured as a percentage, the VSLs should be incremented by 5% with 5% or less as a Lower VSL; more than 5% up to and including 10% as Moderate; more than 10% up to and including 15% as High; and more than 15% noncompliant as a Severe VSL.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-016 R2.	For each Misoperation, the responsible entity that owns an SPS failed to take 5% or less of the corrective actions designed to avoid future SPS Misoperations.	For each Misoperation, the responsible entity that owns an SPS failed to take more than 5% up to (and including) 10% of the corrective actions designed to avoid future SPS Misoperations.	For each Misoperation, the responsible entity that owns an SPS failed to take more than 10% up to (and including) 15% of the corrective actions designed to avoid future SPS Misoperations.	For each Misoperation, the responsible entity that owns an SPS failed to take more than 15% of the corrective actions designed to avoid future SPS Misoperations.

6. If the requirement has a timing element associated with delivering something within a specified number of days and noncompliance is addressed in multiple VSLs, the increments in the number of "days late" should be set at 10 days.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-016 R3.	The responsible entity provided documentation of its SPS Misoperation analyses and the corrective action plans more than 90 calendar days but less than or equal to 120 calendar days following a request from its Regional Reliability Organization or NERC.	The responsible entity provided documentation of its SPS Misoperation analyses and the corrective action plans more than 120 calendar days but less than or equal to 130 calendar days following a request from its Regional Reliability Organization or NERC.	The responsible entity provided documentation of its SPS Misoperation analyses and the corrective action plans more than 130 calendar days but less than or equal to 140 calendar days following a request from its Regional Reliability Organization or NERC.	The responsible entity provided documentation of its SPS Misoperation analyses and the corrective action plans more than 140 calendar days following a request from its Regional Reliability Organization or NERC.

7. The VSLs should be size-neutral so that they treat noncompliance with large and small entities similarly.

When developing VSLs based on percentages or numbers, ensure that the developed VSLs are "size neutral." In some instances, applying a percentage to an entity with a small size may result in grading a violation higher or lower than might be intended. Similarly, applying a fixed number to an entity with a large size may result in a determination of violation that is higher or lower than might have been intended. In such cases, establish VSLs that categorize noncompliant performance by referencing either a percentage of noncompliant performance or a fixed number of noncompliant items.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
MOD-001 R7	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for 5% or less of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater).	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% but less than (or equal to) 10% of all ATC Paths or Flowgates but not more than 2 ATC Paths or Flowgates (whichever is greater).	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10% but less than (ore equal to) 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater).	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater).

In its June 19, 2008 *Order on Violation Severity Levels*, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

> **Guideline 1:** Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance (Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.)
>
> **Guideline 2:** Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties (A violation of a "binary" type requirement must be a "Severe" VSL. Avoid using ambiguous terms such as "minor" and "significant" to describe noncompliant performance.)
>
> **Guideline 3:** Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement (VSLs should not expand on what is required in the requirement.)
>
> **Guideline 4:** Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations (. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.)

In its March 18, 2010 Order Addressing VSL Assignments in CIP Standards, FERC offered the following additional guidance relative to VSLs for CIP requirements:

> Specifically, we have developed the following two additional guidelines for analyzing the validity of Violation Severity Levels that pertain to cyber security:
>
> (1) Requirements where a single lapse in protection can compromise computer network security, i.e., the "weakest link" characteristic, should apply binary rather than gradated Violation Severity Levels; 11 and
>
> (2) Violation Severity Levels for cyber security Requirements containing interdependent tasks of documentation and implementation should account for their interdependence.

General Attributes of the Standard in Total

Scope — Each reliability standard must be within the scope of the associated Standard Authorization Request (SAR). The requirements can address a scope that is smaller than the scope identified in the SAR, but the requirements may not go beyond the work specified in the SAR. If a drafting team wants to develop requirements that go beyond the scope of the SAR, the team must request authorization from the Standards Committee to propose a "supplemental SAR" for stakeholder comment. If a reviewer does not have the technical knowledge to make a judgment, the review may decline from answering this question.

Completeness — Each reliability standard must be complete and self-contained. The standards can't depend on external information to determine the required level of performance.

Practicality — Each reliability standard should establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter. Consideration must be made when assessing the practicality of implementation for the size of the responsible entities (investor owned utilities verses local municipalities and cooperatives).

Consistent Terminology — Each reliability standard, to the extent possible, must use a set of standard terms and definitions (Glossary of Terms Used in NERC Reliability Standards) that are developed and approved through the NERC Reliability Standards Development Process.

Regulatory Directives & Stakeholder Comments — Each drafting team must identify how it addressed each of the issues associated with the standard that were previously identified by stakeholders and regulatory authorities. Drafting Teams may identify a method that is "equally effective and efficient" to achieve the reliability intent of a directive, but if the drafting team does so; it should ask stakeholders (in the comment form) for feedback. For each regulatory directive that is phrased, ". . . direct ... to consider the comments from . . ." the team should provide (in the comment form) its analysis of the proposal, and a question asking stakeholders if they agree with the team's recommendation.

Variances — Each proposed variance must be accompanied by a justification for that variance that explains why the region wants its own criteria to apply rather than the continent-wide criteria. A variance for a requirement must include the requirement, associated measure, evidence retention, VRF, Time Horizon, and VSL. If the drafting team submits a variance it should identify whether the team supports the variance and should identify the impact to the continent-wide standard if the standard were revised so that the variance were not needed.

Compatibility with Existing Standards — Each standard should coordinate with existing enforceable standards without duplicating or conflicting with any already approved requirements.

Implementation Plan

Each standard must have an implementation plan. The plan must include the following elements:

What is proposed for approval /retirement- List of standards (number and title) and definitions that are proposed for approval and any associated retirements of earlier versions of the same standards or definitions.

List of functions that must comply with the requirements in the standards – The plan should include a list of the functional entities that are identified in the applicability section of the proposed standard.

Prerequisite approvals or activities — If the proposed standard cannot be implemented until some other standard is implemented or until some other activity is accomplished, the SDT must identify these prerequisites. If there are no prerequisite approvals, the SDT should include a sentence in the implementation plan that states the proposed standard is not dependent on any prerequisite approvals.

Proposed effective date or dates – The plan must list the proposed effective date or dates and must include a justification for the proposed effective date or dates. The proposed effective date or dates in the Implementation Plan must match the Proposed Effective Date section of the associated standard.

Recommended modifications to already approved standards – If an already approved standard has requirements that need to be modified or retired as a result of a proposed standard, the plan must include an overview of the proposed changes in the implementation plan. In addition, the plan must include a redline version of the proposed changes to the standard to show what language is being changed, and the implementation plan should include an explanation to let stakeholders know why the drafting team believes the suggested change is needed. (The red line should show proposed changes to the last approved version of the standard.)

NERC Statement of Compliance Registry Criteria

http://www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0.pdf

I. Entities that use, own or operate elements of the bulk electric system as established by NERC's approved definition of bulk electric system below are (i) owners, operators, and users of the bulk power system and (ii) candidates for registration: *"As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.4"*

Function Type	Acronym	Definition/Discussion
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a BA area, and supports Interconnection frequency in real- time.
Distribution Provider	DP	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Generator Operator	GOP	The entity that operates generating unit(s) and performs the functions of supplying energy and interconnected operations services.
Generator Owner	GO	Entity that owns and maintains generating units.
Interchange Authority	IA	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Load-Serving Entity	LSE	Secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.

Function Type	Acronym	Definition/Discussion
Planning Authority	PA	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Purchasing-Selling Entity	PSE	The entity that purchases or sells and takes title to energy, capacity, and interconnected operations services. PSE may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the reliable operation of the bulk power system, has the wide area view of the bulk power system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real- time operations. The RC has the purview that is broad enough to enable the calculation of interconnection reliability operating limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each BA's use in recovering from contingencies within the group. Scheduling energy from an adjacent BA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a RSG.
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a PA area.
Transmission Owner	TO	The entity that owns and maintains transmission facilities.

Function Type	Acronym	Definition/Discussion
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission facilities.
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

II. Entities identified in Part I above will be categorized as registration candidates who may be subject to registration under one or more appropriate functional entity types based on a comparison of the functions the entity normally performs against the following function type definitions:

III (a)Load-serving Entity:

III.a.1 Load-serving entity peak load is > 25 MW and is directly connected to the bulk power (>100 kV) system, or;

III.a.2 Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system, or;

III.a.3 Load-serving entity is designated as the responsible entity for facilities that are part of a required undervoltage load shedding (UVLS) program designed, installed, and operated for the protection of the bulk power system.

III.a.4 Distribution providers registered under the criteria in III.b.1 or III.b.2 will be registered as a load serving entity (LSE) for all load directly connected to their distribution facilities.

III(b) Distribution Provider:

III.b.1 Distribution provider system serving >25 MW of peak load that is directly connected to the bulk power system.

III.b.2 Distribution provider is the responsible entity that owns, controls, or operates facilities that are part of any of the following protection systems or programs designed, installed, and operated for the protection of the bulk power system:

- a required UFLS program.
- a required UVLS program.
- a required special protection system.

- a required transmission protection system.

IIII Generator Owner/Operator:

III.c.1 Individual generating unit > 20 MVA (gross nameplate rating) and is directly connected to the bulk power system, or;

III.c.2 Generating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating, or;

III.c.3 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a transmission operator entity's restoration plan, or;

III.c.4 Any generator, regardless of size, that is material to the reliability of the bulk power system.

III(d) Transmission Owner/Operator:

III.d.1 An entity that owns/operates an integrated transmission element associated with the bulk power system 100 kV and above, or lower voltage as defined by the Regional Entity necessary to provide for the reliable operation of the interconnected transmission grid; or

III.d.2 An entity that owns/operates a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity.

Functional Model

http://www.nerc.com/files/Functional_Model_V5_Final_Clean_2009Dec1.pdf

Functional Entity – Planning Coordinator

Definition

The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.

Introduction to the Planning Coordinator

The Planning Coordinator is responsible for assessing the longer-term reliability of its Planning Coordinator area. While the area under the purview of a Planning Coordinator may include as few as one Transmission Planner and one Resource Planner, the Planning Coordinator's scope of activities may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. Planning Coordinators work through a variety of mechanisms to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all network areas with little or no ties to others' areas, such as interconnections, are completely coordinated for planning activities.

Relationships with Other Functional Entities

1. Coordinates and collects data for system modeling from Transmission Planner, Resource Planner, and other Planning Coordinators.
2. Coordinates transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators.
3. Coordinates plans with Reliability Coordinator and other Planning Coordinators on reliability issues.
4. Receives plans from Transmission Planners and Resource Planners.
5. Collects information including:
    a. Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.
    b. Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners.
    c. Generator unit performance characteristics and capabilities from Generator Owners.
    d. Long-term capacity purchases and sales from Transmission Service Providers.

6. Collects and reviews reports on transmission and resource plan implementation from Resource Planners and Transmission Planners.
7. Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Planning Coordinator area with Transmission Planners and Resource Planners and adjacent Planning Coordinator areas, as appropriate.
8. Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system.
9. Facilitates the integration of the respective plans of the Resource Planners and Transmission Planners within the Planning Coordinator area.
    a. Reviews the integrated plan with respect to established reliability needs considering the impact on and by adjoining systems.
    b. In coordination with the Resource Planners and Transmission Planners, facilitates the development of alternative solutions for plans that do not meet those reliability needs.

Functional Entity — Transmission Planner

Definition

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

Introduction to the Transmission Planner

The Transmission Planner is responsible for assessing the longer-term (generally one year and beyond) reliability of its Transmission Planner area. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. Transmission Planners coordinate their plans with the adjoining Transmission Planners to assess impact on or by those plans. The area under the purview of a Transmission Planner may include one or more Resource Planner areas and overlap one or more adjacent Transmission Planners.

Relationships with Other Functional Entities

1. Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, Resource Planners, other Transmission Planners, Transmission Owners, and Transmission Service Providers.

2. Collects information including:

    - Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.

    - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners.

    - Generator unit performance characteristics and capabilities from Generator Owners.

    - Long-term transmission capacity purchases and sales from Transmission Service Providers

3. Informs Resource Planners and other Transmission Planners of the methodologies and tools for the simulation of the transmission system.

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

5. Coordinates the evaluation of Bulk Electric System expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

6. Reports on and coordinates its Bulk Electric System expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

7. Notifies other Transmission Planners, Transmission Owners, Transmission Operators and other entities that may be impacted of any planned Bulk Electric System changes.

8. Coordinates with Distribution Providers, Transmission Owners, Generator Owners and Load-Serving Entities in the evaluation and plans for all requests required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.

9. Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Transmission Planner area with other Transmission Planners and Resource Planners, as appropriate.

10. Coordinates and develops transfer capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners and Transmission Service Providers

11. Coordinates with Transmission Owners and Generator Owners to define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.

12. Receives maintenance schedules and construction plans from Transmission Operator or Transmission Owner for input into and evaluation of Bulk Electric System expansion plans.

Functional Entity — Resource Planner

Definition

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

Relationships with Other Functional Entities

1. Coordinates the resource models with its Planning Coordinator.
2. Coordinates with Transmission Owners and Transmission Planners on the deliverability of resources to customers.
3. Coordinates with and collects data for resource planning from the Load-Serving Entities, Generator Owners, Generator Operators, Transmission Planners, Transmission Operators, Interchange Coordinators, and Reliability Assurers.
4. Coordinates with Transmission Planners, Transmission Service Providers, Reliability Coordinators, and Planning Coordinators on resource adequacy plans.
5. Coordinates with adjoining Resource Planners within the Planning Coordinator area to avoid the double-counting of resources.
6. Reports its resource plan to the Transmission Planner and Planning Coordinator for evaluation and compliance with Reliability Standards.
7. Reports on resource plan implementation to the Transmission Planner, Planning Coordinator and Reliability Assurer.
8. Works with the Planning Coordinator and Transmission Planners to identify potential alternative transmission solutions to meet Resource Planner plans.
9. Applies methodologies and tools for the analysis and development of resource adequacy plans from the Planning Coordinator.

Functional Entity — Reliability Coordinator

Definition

The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.

Introduction to the Reliability Coordinator

The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator's wide-area view. The wide-area view includes situational awareness of its neighboring Reliability Coordinator Areas. Its scope includes both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably.

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

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

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates with other Reliability Coordinators, Transmission Planners, and Transmission Service Providers on transmission system limitations.
2. Receives facility and operational data from Generator Operators, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators.

3. Receives generation dispatch from Balancing Authorities and issues dispatch adjustments to Balancing Authorities to prevent exceeding limits within the Reliability Coordinator Area (if not resolved through market mechanisms).
4. Receives integrated operational plans from Balancing Authorities for reliability analysis of Reliability Coordinator Area.
5. Receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.
6. Develops Interconnection Reliability Operating Limits, based on Transmission Owners' and Generator Owners' specified equipment ratings, and provides them to Transmission Operators.
7. Assists Transmission Operators in calculating and coordinating System Operating Limits.
8. Provides reliability analyses to Transmission Operators, Generator Operators and Balancing Authorities in its area as well as other Reliability Coordinators.
9. Directs Generator Owners and Transmission Owners to revise generation and transmission maintenance plans that are adverse to reliability.
10. Receives balancing information from Balancing Authorities for monitoring.
11. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.
12. Provide IROLs and TTC to the Transmission Service Provider for ATC calculation.
13. Develops operating agreements or procedures with Transmission Owners.
14. Coordinates with Transmission Operators on system restoration plans, contingency plans and reliability-related services.

Real Time

15. Coordinates reliability processes and actions with and among other Reliability Coordinators.
16. Receives Real-time operational information from Balancing Authorities, Interchange Coordinators and Transmission Operators for monitoring.
17. Issues reliability alerts to Generator Operators, Transmission Operators, Transmission Service Providers, Balancing Authorities, Interchange Coordinators, Regional Entities and NERC.
18. Issues corrective actions and emergency procedures directives (e.g., curtailments or load shedding) to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange Coordinators.
19. Specifies reliability–related requirements (e.g., reactive requirements, location of operating reserves) to Balancing Authorities.
20. Receives verification of emergency procedures from Balancing Authorities.
21. Receives notification of Confirmed Interchange changes from Balancing Authorities.
22. Orders redispatch of generation by Balancing Authorities.
23. Directs use of flow control devices by Transmission Operators.

24. Responds to requests from Transmission Operators to assist in mitigating equipment overloads.

Functional Entity — Balancing Authority

Definition

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

Relationships with Other Functional Entities

Ahead of Time

1. Receives operating and availability status of generating units and operational plans and commitments from Generator Operators within the Balancing Authority Area.
2. Receives annual maintenance plans from Generator Owners within the Balancing Authority Area.
3. Receives reliability evaluations from the Reliability Coordinator.
4. Receives final approval or denial of a request for an Arranged Interchange from the Interchange Coordinators.
5. Compiles load forecasts from Load-Serving Entities.
6. Develops agreements with adjacent Balancing Authorities for ACE calculation parameters.
7. Submits integrated operational plans to the Reliability Coordinator for reliability evaluation and provides balancing information to the Reliability Coordinator for monitoring.
8. Confirms Arranged Interchange with Interchange Coordinators.
9. Confirms ramping capability with Interchange Coordinators.
10. Implements generator commitment and dispatch schedules from the Load-Serving Entities and Generator Operators who have arranged for generation within the Balancing Authority Area.
11. Acquires reliability-related services from Generator Operator.
12. Receives dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
13. Receives generator information from Generator Owners including unit maintenance schedules and retirement plans.
14. Receives information from Load-Serving Entities on self-provided reliability-related services.
15. Coordinates system restoration plans with Transmission Operator.
16. Provides generation dispatch to Reliability Coordinators.

Real Time

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

18. Receives loss allocation from Transmission Service Providers (for repayment with in-kind losses).
19. Receives Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators.
20. Receives operating information from Generator Operators.
21. Provides Real-time operational information for Reliability Coordinator monitoring.
22. Receives reliability alerts from Reliability Coordinator.
23. Complies with reliability-related requirements (e.g., reactive requirements, location of operating reserves) specified by Reliability Coordinator.
24. Verifies implementation of emergency procedures to Reliability Coordinator.
25. Informs Reliability Coordinator and Interchange Coordinators of Confirmed Interchange changes (e.g., due to generation or load interruptions) involving its Balancing Authority Area.
26. Directs resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in real time.
27. Directs Transmission Operator (or Distribution Provider) to reduce voltage or shed load if needed to ensure balance within its Balancing Authority Area.
28. Directs Generator Operators to implement redispatch for congestion management as directed by the Reliability Coordinator.
29. Implements corrective actions and emergency procedures as directed by the Reliability Coordinator.
30. Implements system restoration plans as directed by the Transmission Operator.
31. Directs Transmission Operator to implement flow control devices.
32. Receives information of Implemented Interchange and Confirmed Interchange curtailments from Interchange Coordinator.

After the hour

33. Confirms Implemented Interchange with Confirmed Interchange provided by the Interchange Coordinators after the hour for “checkout.”
34. Confirms Implemented Interchange and Confirmed Interchange with adjacent Balancing Authorities after the hour for “checkout.”

Functional Entity — Transmission Operator

Definition

The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area.

Introduction to the Transmission Operator

The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

The Transmission Operator and Reliability Coordinator have similar roles with respect to transmission operations, but different scopes. The Transmission Operator scope is narrower than the Reliability Coordinator, and the Transmission Operator does not necessarily "see" very far beyond its own boundaries. Therefore, the Transmission Operator can calculate System Operating Limits, but will not necessarily calculate Interconnection Reliability Operating Limits, which requires the wider scope of the Reliability Coordinator.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates restoration plans with Reliability Coordinator, Transmission Operators, Balancing Authorities, and Distribution Providers.
2. Receives maintenance and construction plans and schedules from the Transmission Owners and Generation Owners.
3. Receives Interconnection Reliability Operating Limits as established by the Reliability Coordinator.
4. Receives reliability evaluations from the Reliability Coordinator.
5. Develops agreements with adjacent Transmission Operators for joint transmission facilities.
6. Defines Total Transfer Capabilities and System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator.
7. Arranges for reliability-related services from Generator Operators.
8. Develops contingency plans, and monitors operations of the transmission facilities within the Transmission Operator Area control and as directed by the Reliability Coordinator.
9. Provides facility and operating information to the Reliability Coordinator.
10. Provides to the Transmission Planner information on the capability to curtail (reduce) and shed load during emergencies.

11. Provides Total Transfer Capabilities and System Operating Limits to, and coordinates Available Transfer Capability with, Transmission Service Provider.
12. Receives operating and availability status of generating units from Generation Operators including status of automatic voltage regulators.
13. Develops operating agreements or procedures with Transmission Owners.

Real Time

14. Coordinates load shedding with, or as directed by, the Reliability Coordinator.
15. Provides Real-time operations information to the Reliability Coordinator and Balancing Authority.
16. Notifies Generator Operators of transmission system problems (e.g., voltage limitations or equipment overloads that may affect generator operations).
17. Requests Reliability Coordinator to assist in mitigating equipment overloads. (e.g., redispatch, transmission loading relief).
18. Deploys reactive resources from Transmission Owners and Generator Owners to maintain acceptable voltage profiles.
19. Directs Distribution Providers to shed load if needed to ensure reliability within the Transmission Operator Area.
20. Implements flow control device operations for those ties under the Transmission Operator's purview as directed by the Balancing Authorities or Reliability Coordinator.
21. Receives reliability alerts from Reliability Coordinator.
22. Directs Balancing Authorities and Distribution Providers to implement system restoration plans.

Functional Entity — Interchange Coordinator

Definition

The functional entity that ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas.

Relationships with Other Functional Entities

Ahead of Time

1. Receives Arranged Interchange from Purchasing-Selling and Load-Serving Entities.
2. Submits request for an Arranged Interchange to become Confirmed Interchange to the Balancing Authorities and Transmission Service Providers for approvals.
3. Receives approval or denial from Transmission Service Providers of transmission arrangement(s) for Arranged Interchange.
4. Receives approval or denial from Balancing Authorities of the ability to meet ramping requirements for submitted Arranged Interchange.
5. Communicates final approval or denial of a request for an Arranged Interchange to become Confirmed interchange to the Reliability Coordinator, Balancing Authorities, Transmission Service Providers, Purchasing-Selling Entities, and Load-Serving Entities for implementation and NERC identified reliability analysis services.

Real Time

6. Receives curtailments and redispatch implementation requests from Reliability Coordinators for an Arranged Interchange.
7. Receives information on Confirmed Interchange interruptions from the Balancing Authorities and communicates the Confirmed Interchange status to Balancing Authorities, Transmission Service Providers, Reliability Coordinators, and Purchase-Selling/Load-Serving Entities.
8. Informs Transmission Service Providers, Purchasing-Selling/Load-Serving Entities, Reliability Coordinators, and Balancing Authorities of Confirmed Interchange revisions (including curtailments).

After the hour

9. Maintains and provides a record of individual Confirmed Interchange for which it coordinated with the Balancing Authorities.
10. Coordinates Confirmed Interchange with Balancing Authorities after the hour for “checkout.”

Functional Entity — Transmission Service Provider

Definition

The functional entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.

Relationships with Other Functional Entities

Ahead of Time

1. Receives Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from Planning Coordinator, Transmission Planner, Transmission Operator and Reliability Coordinator, and coordinates Available Transfer Capability with these entities and other Transmission Service Providers.
2. Receives transmission Facility Ratings from Transmission Owners.
3. Receives transmission expansion plans identified by the Planning Coordinator to help determine ability to accommodate long-term transmission service requests.
4. Approves or denies transmission service requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities.
5. Confirms validity of transmission service requests indicated in the Arranged Interchange with Interchange Coordinators.
6. Develops agreements or procedures with Transmission Owners.
7. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.

Real Time

8. Receives Confirmed Interchange revisions (including curtailments) from the Interchange Coordinators.
9. Receives reliability alerts from Reliability Coordinator.
10. Provides loss allocation to Balancing Authorities.

Functional Entity — Transmission Owner

Definition

The functional entity that owns and maintains transmission facilities.

Relationships with Other Functional Entities

1. Coordinates with Transmission Planners and the Planning Coordinator, Generator Owners, other Transmission Owners, and Load-Serving Entities desiring to connect with the Bulk Electric System.
2. Receives approved transmission expansion plans from the Transmission Planner.
3. Develops agreements or procedures with the Transmission Service Providers.
4. Develops operating agreements or procedures with the Transmission Operators, Reliability Coordinators and Distribution Providers.
5. Develops agreements with adjacent Transmission Owners for joint transmission facilities.
6. Provides transmission expansion plans and changes to the Planning Coordinator and Transmission Planners.
7. Provides transmission Facility Ratings to Transmission Operators, Reliability Coordinators, Transmission Service Providers, Distribution Providers, Transmission Planners, and Planning Coordinator.
8. Provides maintenance and construction plans and schedules to the Reliability Coordinator, Transmission Operator, and Transmission Planner.
9. Develops interconnection agreements with the Distribution Providers and Generation Owners for connecting to the Bulk Electric System.
10. Provides reactive resources to Transmission Operators.
11. Revises transmission maintenance plans as requested by the Reliability Coordinator.

Functional Entity — Distribution Provider

Definition

The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.

Introduction to the Distribution Provider

The Distribution Provider delivers electrical energy to the End-use Customer from the transmission system. For those End-use Customers who are served at transmission voltages, the Transmission Owner may also serve as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. The Distribution Provider provides the switches and recloses that could be used to shed load for emergency action.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates with Transmission Planners on transmission expansion.
2. Coordinates system restoration plans with Transmission Operator.
3. Coordinates with End-use Customers and Load-Serving Entities to identify new facility connection needs.
4. Develop interconnection agreements with Transmission Owners on a facility basis.
5. Provides operational data to Transmission Operator.
6. Coordinate with Load-Serving Entities to identify critical loads that are to be precluded from load shedding where avoidable.

Real Time

7. Implements voltage reduction and sheds load as directed by the Transmission Operator or Balancing Authority.
8. Implements system restoration plans as coordinated by the Transmission Operator.
9. Directs Load-Serving Entities to communicate requests for voluntary load curtailment.

Functional Entity — Generator Operator

Definition

The functional entity that operates generating unit(s) and performs the functions of supplying energy and reliability-related services.

Relationships with Other Functional Entities

Ahead of Time

1. Provides generation commitment plans to the Balancing Authority.
2. Provides Balancing Authority and Transmission Operators with requested amount of reliability-related services.
3. Provides operating and availability status of generating units to Balancing Authority and Transmission Operators for reliability analysis.
4. Reports status of automatic voltage or frequency regulation equipment to Transmission Operators.
5. Provides operational data to Reliability Coordinator.
6. Receives reliability analyses from Reliability Coordinator.
7. Receives notice from Purchasing-Selling Entity if Arranged Interchange approved or denied.
8. Receives reliability alerts from Reliability Coordinator.
9. Receives notification of transmission system problems from Transmission Operators.

Real Time

10. Provides Real-time operating information to the Transmission Operators and the required Balancing Authority.
11. Adjusts real and reactive power as directed by the Balancing Authority and Transmission Operators.

Functional Entity — Generator Owner

Definition

The functional entity that owns and maintains generating units.

Relationships with Other Functional Entities

1. Provides generator information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner.
2. Provides unit maintenance schedules and unit retirement plans to the Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner.
3. Develops an interconnection agreement with Transmission Owner on a facility basis.
4. Receives approval or denial of transmission service request from Transmission Service Provider.
5. Provides reliability-related services to Purchasing-Selling Entity pursuant to agreement.
6. Reports the annual maintenance plan to the Reliability Coordinator, Balancing Authority and Transmission Operator.
7. Revises the generation maintenance plans as requested by the Reliability Coordinator.

Functional Entity — Purchasing-Selling Entity

Definition

The functional entity that purchases or sells, and takes title to, energy, capacity, and reliability-related services.

Relationships with Other Functional Entities

Ahead of Time

1. Arranges for transmission service from Transmission Service Providers and makes arrangements for reliability-related services with Generator Owners or Load-Serving Entities.
2. Submits Requests For Interchange to Interchange Coordinators.
3. Notifies Generator Operators and Load-Serving Entities if Arranged Interchange requests are approved or denied.
4. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.
5. Receives load profiles and forecasts from Load-Serving Entities.

Real Time

6. Notifies Interchange Coordinators of Confirmed Interchange and Implemented Interchange cancellations or terminations.
7. Receives notice of Confirmed Interchange curtailments from Interchange Coordinator.

Functional Entity — Load-Serving Entity

Definition

The functional entity that secures energy and transmission service (and reliability-related services) to serve the electrical demand and energy requirements of its end use customers.

Relationships with Other Functional Entities

Ahead of Time

1. Submits load profiles and characteristics, plans, and forecasts as needed to the Balancing Authorities, Purchasing-Selling Entities, Planning Coordinator, Resource Planners, and Transmission Planners.
2. Identifies new facility connection needs for End-use Customers.
3. Provides generation commitments and dispatch schedules to the Balancing Authority.
4. Provides information as to self-provided reliability-related services to the Balancing Authority.
5. Provides planned purchases to the Resource Planner and Transmission Planner for system modeling and reliability evaluation.
6. Arranges for transmission service from Transmission Service Providers and makes arrangements for reliability-related services with Generator Owners or Load-Serving Entities
7. Submits Requests For Interchange to Interchange Coordinators.
8. Notifies Generator Operators if Arranged Interchange requests are approved or denied.
9. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.
10. Coordinates with Distribution Provider on identifying new facility interconnection needs.
11. Receives notification from Purchasing-Selling Entity if Arranged Interchange requests approved or denied.

Real Time

12. Receives requests from the Balancing Authority and Distribution Provider for voluntary load curtailment.
13. Communicate requests for voluntary load curtailment to end-use customers as directed by the Balancing Authority and Distribution Provider.
14. Notifies Interchange Coordinators of Confirmed Interchange cancellations or terminations.
15. Receives notice of Confirmed Interchange curtailments from Interchange Coordinator.

Version History:

Date	Page	Action
October 6, 2010	Page 28	Added description of "Scope" to clarify that the scope of the proposed requirements must be within the scope of the project identified in the SAR.
December 8, 2010	Page 4	Added language to clarify that if a requirement references an Attachment, the Attachment must be reviewed.
February 17, 2011	Page 7	Added fourth bullet under "Measures" to identify that attestations are acceptable and must be made by an individual on behalf of an entity.
	Page 14	Added default language for identification of CEA
	Page 30	Added CIP VSL Guidelines from FERC's March 18, 2010 Order Addressing VSL Assignments for CIP Reliability Standards
July15, 2011	Page 6-7	Added a sample paragraph and associated explanation advising entities that they may be asked to prove they were compliant for the entire time period since the last audit.
August 23, 2011	Page 14	Modified the language for the Compliance Enforcement Authority
	Page 14	Changed the Compliance Monitoring Process called, "Compliance Violation Investigations" to "Compliance Investigations" to match a change to the title of that process in the ROP.
September 22, 2011	Page 3	Added a sentence to the Purpose section to clarify that the requirements in the proposed standard should, collectively, support the purpose statement. Moved information into new NERC report format.
January 7, 2012	Page 7	Changed the phrase, "until found compliant" to "until mitigation is complete and approved" in the third (next to last) paragraph on this page.
January 7, 2012	Page 15	In the section called, "Compliance Enforcement Authority 1.1:"

		Replaced the following: For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority. For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority. For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority. With: The Regional Entity shall serve as the Compliance enforcement authority 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.

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Inside FERC

January 2, 2012

Wellinghoff questions NERC performance, eyes more gas refund, transmission authority

More than five years after FERC first gave North American Electric Reliability Corporation the responsibility to develop and enforce reliability standards, Chairman Jon Wellinghoff is questioning whether another entity could do a better job.

"I think there are some real, real, real serious issues with respect to the functioning of NERC," Wellinghoff told Platts in a recent interview that touched on a variety of electric and natural gas issues.

He noted that FERC is currently performing its first audit of NERC's financial performance. "We're paying a lot of money for NERC," he said. "I want to know if we're getting our money's worth for what they do or whether the function can be performed cheaper, better by somebody else."

Wellinghoff also renewed his call for Congress to expand the commission's authority in several key areas, including ordering refunds in gas pipeline rate investigations and siting transmission lines. But he was not optimistic. "I'm not holding my breath on any legislation," he explained.

The commission can "get along" with its current authority on these issues, the chairman claimed. But in the case of pipeline rates, he said he would rather wait for Congress to give rate investigations more teeth than have FERC administratively require more frequent rate cases that

(continued on page 17)

that would allow a team to continue operating for an extended period in case of major storms or similar emergencies. There are monitors in each center showing a real-time view of the other.

Dotter says the grid operations system is a sign of how far the power industry has come. Prior to the modern version of PJM, a utility seeking to move power from Chicago to New Jersey, for example, would have to create agreements with each of the utilities that would be involved, he said. "What we've done is organize it and make it easier to do."

And the demands of grid management keep evolving, Boston noted. "Among our biggest challenges are the changes in the generation portfolio coming in the near future," he said, pointing to coal plant retirements that will pose local reliability issues.

"At the same time, we expect to see new generation developed from the abundance of shale gas, although the location of the generation relative to the transmission system and customer demand may be a challenge. In much the same way, the continued growth of renewable generation poses challenges to grid operators because it tends to be located away from population centers. Through it all, operators will have to balance line outages, new interconnections, plant retirements and power outages," said Boston.

— Martin Coyne

Wellinghoff questions NERC performance, eyes more authority ... from page 1

could become unwieldy.

No matter what happens in Congress, some of FERC's activities in 2012 are likely to involve the commission defining its roles and/or jurisdiction in oversight of financial futures markets, managing any reliability impacts of federal environmental regulations and helping DOE with the electric grid congestion study and corridor designation processes, the chairman said.

As for NERC, Wellinghoff hopes the audit covering the period of August 23, 2006, to the present (FA11-21) will compare NERC's performance with those of similar entities, such as the North American Energy Standards Board. "I'm very interested and anxious to see results of that audit," Wellinghoff said. When FERC in July 2006 certified NERC as the electric reliability organization, it promised to conduct periodic financial performance audits.

"We can revisit whether NERC is the appropriate ERO or not at any time, as I read the statute," the chairman said. "It's been now five years since we've reviewed what they're doing and so it's appropriate now to do a full-blown review and determine whether or not they're still the appropriate entity to carry out these functions." He said the audit might be finished in the spring.

Wellinghoff expressed "great reservations" about approving the 2012 NERC budget because of the ongoing audit. In a statement attached to FERC's October 20 approval of the $160.9 million budget, he said that, "in my view, there is no legal barrier to the commission's ability to revisit NERC's 2012 budget and business plan in light of the results of the audit."

"While it would be premature to comment on the ongoing audit," a NERC spokeswoman late last month said it "has always operated in an open, transparent manner and will continue to do so. NERC's budget receives review and final approval from FERC each year."

"Reliability and accountability are our benchmarks, and all NERC program areas focus on delivering exceptional value with regard to bulk power system reliability for electricity customers and reliability stakeholders," she said. "We look forward to any opportunities the FERC audit affords us to continually improve as the electric reliability organization."

Regarding Wellinghoff's legislative priorities, he said new authority on pipeline rate refunds and transmission siting is at the top of his list. But he noted that the commission could carry on even without congressional action.

"I think the biggest one is transmission siting, ultimately, and the Natural Gas Act reform. Those would be the most desirable ones, but we can get along without them," he said. "Ultimately, we are, I think, doing a pretty good job under the legislative authority we have right now and we continue to do . . . a tremendous amount in energy policy without any additional legislative authority."

On the issue of NGA reform, Wellinghoff said he wants Congress to give the commission new authority to order refunds in gas pipeline and storage rate investigations.

Under current law, the commission can launch an NGA Section 5 investigation into pipeline rates either on its own or at the prompting of customers who claim they are being overcharged. However, once FERC makes a decision on the investigation, it can only order the pipeline to change its rates going forward. The commission cannot require pipelines to issue refunds retroactively back to the beginning of the investigation or the date a complaint was filed.

Congress should give FERC authority under the NGA similar to its authority under the Federal Power Act, which allows the commission to order a company to refund excessive rates dating back to the time an investigation began, Wellinghoff said. "We need to see legislative reform," he said. "I think the way the process is now, it puts all the leverage on the side of the pipeline," he said. "They can just drag it out as long as they want to and they continue to collect the higher rates until the case is decided."

FERC could take administrative steps to try to prevent excessive gas pipeline rates. For example, the commission could require pipeline operators to periodically apply to revise their tariffs under NGA Section 4 to ensure they remain reasonable. "That might be an alternative to reform," he said.

But while the chairman was skeptical Congress would act on FERC's priorities, he would still rather wait for NGA legislation than pursue an administrative fix. New refund authority would be more efficient for regulators, he explained.

"If you make somebody periodically file a case, . . . sometimes you just set up a system that needlessly overburdens the regulatory system by having cases that are not necessary. I think it is better to set up a system where you can have a fair

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process for either party, either the pipeline or a complainant," Wellinghoff said.

For years, FERC required pipelines to file a rate case every three years. It dropped that requirement in 1992 when it issued Order 636, which finalized the restructuring of the gas pipeline industry to encourage competition. Since that time, pipeline operators have been able to go for many years without formally revising their rates.

For example, the commission last month launched three rate investigations into companies that have not filed cases to review their rates in at least 18 years (*IF*, 21 Nov, 1).

On transmission, Wellinghoff said clarification from Congress on FERC's backstop siting authority under the Energy Policy Act of 2005 would fix what he called a "very onerous process that can be subject to a lot of legal challenges."

EPAct added Section 216 to the Federal Power Act under which FERC may site new or modify existing electric transmission facilities in DOE-designated national interest electric transmission corridors when states fail to act on a transmission project application for more than a year, and under a few other circumstances. FERC has yet to use that authority, and a federal court decision invalidating DOE's designation of the corridors means the commission cannot act now anyway.

Wellinghoff believes the commission's 2006 interpretation of EPAct — that it allows FERC to override a state's denial of a transmission project — is the correct one. The 4th US Circuit Court of Appeals in 2009 overturned that interpretation, finding that Congress never intended to give FERC the right to overturn a state's decision on a transmission project (*IF*, 23 Feb '09, 1).

DOE is currently performing another grid congestion study, which may result in the designation of new corridors.

The commission has "an advisory role" in the DOE corridor designation and study processes, Wellinghoff said. "We certainly will provide advice to them, to the extent that they require it." But "it remains to be seen how much they'll require our advice or how much they'll actually use it." The chairman said he was scheduled to meet before Christmas with Lauren Azar, DOE senior adviser to the secretary of energy on electric transmission.

DOE for a brief period last year contemplated delegating to FERC the tasks of performing a congestion study and making corridor designations (*IF*, 17 Oct, 1). Following pushback from states and members of Congress, DOE ditched that proposal.

Wellinghoff would like to see DOE consider project-specific designations or smaller corridors than the ones the agency picked the first time. "If a project [developer] comes in and says, 'we're going to do a project from A to B, and we think it should be a corridor,' I think DOE should consider doing an analysis to see if it is in fact a congestion corridor and whether or not it could be part of the process." That was what FERC would have done if the corridor designation task had been given it, he said.

One of the major criticisms of DOE's initial corridor designations was the size of the two corridors it identified in the Southwest and Mid-Atlantic. More than 150,000 square miles in 10 states and the District of Columbia were included in the corridors.

"All of what we were proposing to do under the delegation" could still be done by DOE "on their own, with some assistance and consultation with us. And we still think that DOE should consider doing that," Wellinghoff said.

Although FERC understands its role in the corridor process will be limited, it is still trying to protect its authority in another area. It is working to convince the Commodity Futures Trading Commission that FERC must retain jurisdiction over financial markets operated by regional transmission organizations and involving certain bilateral transactions.

Nearly one year after FERC and CFTC missed their deadline to reach two agreements aimed at sorting out their long-standing jurisdictional battles, the agencies are still at odds over which one should be in charge of overseeing transactions in wholesale electricity markets, Wellinghoff said. "There's still a difference of opinion between us and CFTC in that regard," he explained.

The Dodd-Frank Wall Street Reform and Consumer Protection Act required FERC and CFTC to negotiate two memorandums of understanding covering information-sharing and procedures for applying their regulatory authorities within 180 days of the act becoming law. That deadline came and passed in January 2011 and there appears to be little hope in sight of the commissions finding a resolution.

FERC officials have urged the CFTC to exempt a number of agreements FERC currently oversees, such as financial transmission rights, from being defined as swaps and subject to the new rules CFTC is developing under Dodd-Frank.

"All I know is that we continue to submit comments to the CFTC, where appropriate, supporting and arguing in our position that we believe that any type of transaction within an RTO should be under our jurisdiction, whether it be a physical trade, or whether it be purely financial," and any other type of agreement FERC currently oversees, such as bilateral transactions in non-RTO markets, Wellinghoff said.

But the CFTC continues "to come out with rules that seem to say: 'Oh, we, CFTC, have jurisdiction in these RTO markets,' " Wellinghoff said. And FERC continues to submit responses in those rulemakings saying: "No, we don't think so," he added.

FERC believes it "should retain that jurisdiction," Wellinghoff said. "To be able to police the whole entire scope of transactions, it's very, very important, and there's some cases that I think you're going to see here very soon that will demonstrate that," the chairman said in foreshadowing the possibility that FERC may be disclosing some non-public investigations in the near future.

When informed of Wellinghoff's statements, CFTC Chairman Gary Gensler declined to comment on the status of the MOUs with FERC, but indicated that his agency was focused instead on the potential exemptions from the CFTC's still-developing derivatives regulatory regime.

CFTC staff has been working with RTOs and independent system operators on an application for exemptive relief from the new swaps rules. These organizations plan to file a single application, but the filing is not expected to take place until sometime next year, Gensler said.

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"We've been ready, and still stand ready, to put that on our website and get public comment," he said following a CFTC meeting last month.

The RTOs and ISOs expect to file their exemption request in early 2012, Ray Hepper, ISO New England general counsel said December 20. Getting to that point has involved all of the regional organizations working together and with CFTC staff "just to get the whole application put together completely" and with all of the descriptions the agency needs, he said.

In April, the CFTC unveiled a proposed definition of swaps that punted on the issue of FTRs. Instead of proposing to define FTRs as swaps, which would subject them to CFTC oversight, or exempting them from the developing regulations, the CFTC instead proposed having RTOs and ISOs make the case to it why FTRs should remain under the exclusive jurisdiction of FERC.

CFTC staff has also been working with rural electric cooperatives and municipal power authorities for nearly six months on their own exemptive relief from the CFTC new swap rules, Gensler said.

He said that CFTC staff has met regularly with FERC staff on potential jurisdictional issues, but declined to comment further. CFTC Commissioner Scott O'Malia, who has worked on FERC jurisdictional issues in the past, declined to comment.

Depending on what EPA includes in its rule on mercury and air toxics standards, Wellinghoff said the commission could play a role in working with the power industry and EPA on handling any reliability problems caused by coal-plant retirements.

EPA on December 21 released its controversial rule to reduce mercury and air toxics from coal- and oil-fired electric generating units that included significant guidance for the power sector to comply within four years or more (see story in this issue).

In an apparent attempt to appease industry's strident calls for more compliance time, EPA also released detailed enforcement office guidance on how power plant operators can seek a fifth year to meet the rule in accordance with the federal statute.

"Once we see what EPA has proposed in their rule, then there may be some possibility that we'll issue a policy statement" or something similar "that will set forth how we will implement what EPA is suggesting they may do, with respect to any kind of safety valve," Wellinghoff said.

The commission's main priorities in 2012 will be finding ways to improve efficiencies in markets and electric and gas system operations, he said.

Inside of those overarching goals, "we want to make sure that the initiatives that we've undertaken in this last year are effectively implemented," such as Order 1000 on transmission planning and cost allocation. Compliance filings on that rule are due next October and another set is due in April 2013.

FERC also hopes to take the next steps in several pending rulemakings left over from 2011, he said.

For example, commission staff is drafting a final rule that would eliminate some barriers to integrating variable energy resources into the grid and power markets, Wellinghoff said. The November 2010 proposed rule would reform the open-access transmission tariffs and large generator interconnection agreements of public utility transmission providers to require them to offer ancillary services to resources such as wind, solar and hydrokinetics (*IF*, 22 Nov '10, 1). Additionally, renewable resources such as wind and solar would provide more forecasting and operational data (RM10-11).

The language for the final rule is "still in draft form," Wellinghoff said. "It hasn't been finalized for commission review yet, so it's going to be a couple [of] months at least."

On the gas side, Wellinghoff said he would continue to pursue policies that promote energy efficiency, such as encouraging the use of gas compressors that generate electricity from waste heat. "We are trying to look at some technologies to see if we can expand the candidates for that type of activity," he said.

FERC is also focusing on improving coordination between gas pipelines and power plants, which are increasingly relying on gas as a fuel due to EPA rules, lower gas prices and other market forces, he said.

The interdependence of the two industry sectors has been a consistent issue in the Northeast and is a growing factor in Texas and New Mexico after last-year's winter outages, he said. "It is becoming an issue of interest — I won't say concern — but an issue of interest that we want to see if there needs to be potential modifications of gas tariffs for ensuring deliverability of gas to natural gas generating facilities," he said.

As a first step, FERC could hold a technical conference to gather input on whether tariff changes are needed, but the commission does not yet have any firm plans for a conference or a notice of inquiry, Wellinghoff said. "I know that there is some general interest [at the commission]. We just haven't sat down and talked about it yet."

Wellinghoff also weighed in on the infrastructure impacts stemming from the shale gas boom, expressing some concern about the viability of new long-haul pipelines in the West and Midwest. "To some extent we are always concerned about the cost of very large infrastructure and how it is going to be recovered. I am ultimately hoping that their investments will in fact be positive, although I know the Ruby Pipeline hasn't been at full capacity," he said.

Several large pipelines came online just as shale gas was transforming the market. For example, El Paso's 680-mile Ruby system went into service in late July and connects gas supplies in Opal, Wyoming, with interconnections near Malin, Oregon. And Kinder Morgan's 1,679-mile Rockies Express Pipeline went into service in November 2009 and carries gas from Colorado to eastern Ohio. These massive lines can be underutilized because shale gas close to large eastern markets is displacing gas from the West.

However, the chairman predicted that power generators will step up and take capacity on these new lines anyway. "I think we are going to see a lot more gas use overall in the country, primarily for generation. So I think you are going to see the need for pipeline capacity increase and so I think those pipelines, too, will see their capacity filled to the point that they become profitable," he said.

Liquefied natural gas import terminals in the US are also seeking

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to take advantage of shale resources by applying to export domestic gas. While DOE is in charge of approving the exports, FERC decides whether the liquefaction facilities can be built.

The commission in the past has changed its policies to ease approval of LNG-import projects. For instance, in 2002 it decided to drop its open-access tariff restrictions for LNG terminals in an effort to encourage construction of import terminals.

However, FERC is not planning any policy changes to grease the skids for LNG export projects, Wellinghoff said. "I haven't heard anything from the industry. . . . There have been some requests for exports, certainly, but there has been no request to change policy in any way with respect to export issues. So I expect that at least in the coming year we will continue to handle those on a case-by-case basis as those applications for export come in," he said.

Shale gas has also displaced demand for gas supplies from the Gulf of Mexico, which is steadily shrinking. Gas pipelines in that region are seeing a drop in utilization and an increase in maintenance costs, and some are seeking to spin off their offshore facilities to affiliates or subsidiaries. The selling companies argue that they no longer need the facilities, but some shippers say it is just an attempt to increase their charges (*IF*, 17 Oct, 4).

FERC would be wary of a spin-off plan that is intended to hike charges, Wellinghoff said. "I don't think we would look favorably to that kind of a structure if it was simply to increase rates to shippers. I mean, I can't think of a specific case where I have seen that happen."

But in general, the chairman said the gas industry — and FERC's oversight of it — seems to take care of itself. The commission rarely discusses gas decisions at its meetings because they are not controversial, he explained. "The markets are working so well on the gas side and there are a lot fewer issues there with respect to how those markets are operating and how the pipeline infrastructures are going into place," he said.

"We really don't get a lot of cases that have a lot of big issues like, you know, the proper payment for demand response. I mean, you don't get those kinds of issues in gas cases or the controversy between us and the CFTC on markets in the electric area. The gas side of the house almost runs itself."

Some recent FERC decisions — such as requiring market-based storage facilities to seek capacity turnback before expanding — have raised the ire of gas industry officials (*IF*, 31 Oct, 1). But even these decisions are not as contentious as FERC's other work, Wellinghoff said. "It doesn't rise to the level of many of the things that we get on the electric side of things," he said.

FERC is also ready to handle the deluge of pipeline construction applications related to rapidly expanding shale gas production, he said. "I don't think we should have any problem with respect to meeting those resource needs," he said.

"We are able to scale up our projects office pretty rapidly. They are the largest office in the commission. . . . And we can also go out and hire contractors to assist us in the environmental studies and other things that are needed to do those."

— Kate Winston, Esther Whieldon, Brian Scheid

LIQUEFIED NATURAL GAS

Total, Cheniere still eye LNG export deal but contract hurdles remain, report says

France's Total is still negotiating with Cheniere Energy to buy liquefied natural gas from the proposed Sabine Pass export project in Louisiana, but talks have stalled over potential *force majeure* issues, according a recent consultancy report.

Total is concerned that the US government might withdraw Cheniere's licenses to export US-made LNG if there is political pressure to do so, and is balking at Cheniere's request that Total pay a fixed charge for the full contractual amount for two years if a *force majeure* event prevents exports, said a Poten & Partners report.

"There is no way Total was going to agree to pay the fixed fee for two years if the export licenses given to Sabine Pass were rescinded," an unnamed source was quoted as saying in the report.

Total spokesman Frederic Texier and Cheniere spokesman Andrew Ware both declined to comment on the report.

Ware told Platts earlier last month that Cheniere believes there will be enough shale gas production in the US to not endanger the export licenses the company has received. He said comments by US officials that the licenses could be revisited if LNG exports materially impact the US gas market were expected, as any country would prioritize its domestic interests ahead of exports, but Cheniere does not expect that to become an issue.

The UK's BG in October signed a deal to buy as much as 3.5 million mt/yr of LNG (equivalent to 448,000 Mcf/d of gas) from Sabine Pass for 20 years, and a month later Gas Natural Fenosa became the second company to contract for Sabine Pass exports. The Spanish company also agreed to buy as much as 3.5 million mt/yr for 20 years (*IF*, 28 Nov, 4).

BG and Gas Natural do not have to buy LNG, but they do have to pay a fixed charge for the full contractual amount. BG would pay $2.25/MMBtu, or $410 million a year, while Gas Natural would pay $2.49/MMBtu, or $454 million a year. If BG and Gas Natural buy LNG under their contracts, they also would pay 115% of the Henry Hub gas futures contract for the month in which a cargo is scheduled for the gas that would be liquefied, as about 15% of the gas would be used in the liquefaction process.

BG would buy supplies from train 1, which would come online in late 2015, while Gas Natural would buy supplies from train 2, which would come online in mid- to late 2016.

Earlier last month, Indian state-owned gas utility GAIL became the third company to sign a contract to buy 3.5 million mt/yr from Sabine Pass for 20 years. GAIL would pay a fixed charge of $3.00/MMBtu, or $547.5 million a year. Cheniere spokeswoman Ware said it was not yet clear if GAIL would have the same ability as BG and Gas Natural to only buy LNG when it wants. GAIL would also pay 115% of the Henry Hub price for gas that would be liquefied.

GAIL would buy supplies from the planned train 4, which would come online in 2017, the Indian company said. In addition, it would buy bridging supplies of 200,000 mt/yr from train 2 when it comes online, until commercial deliveries start from train 4. Ware told

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From: Guy V. Zito
To: Lee R. Pedowicz
Subject: FW: NERC: Standards Development Process and Cybersecurity Standards Forum
Date: Monday, January 23, 2012 12:23:57 PM

We should have this on the agenda for the next RSC meeting.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

_____
From: david.kiguel@HydroOne.com [david.kiguel@HydroOne.com]
Sent: Wednesday, January 18, 2012 9:01 AM
To: ben@benli.ca; Guy V. Zito; Gerard J. Dunbar; carol.sedewitz@us.ngrid.com; diane_barney@dps.state.ny.us
Subject: RE: NERC: Standards Development Process and Cybersecurity Standards Forum

Another interesting twist on NERC's plans to hold a Standards Summit unfolded yesterday. The NERC Electricity Sub-Sector Coordinating Council held a conference call this afternoon. During this call, Gerry Cauley reported that the summit has been deferred in order to allow several things to happen first:

1. NERC will prepare formal problem statements with respect to CIP standards and the standards development process in general. NERC plans to release these statements publicly by end of January, and wants CEOs and industry leaders to review and discuss them.

2. NERC then plans to convene small focus groups, divided by sector, to review these problem statements. (Gerry mentioned approaching trade associations and Canadians as part of this effort). Through these focus groups, Gerry hopes to have frank conversations at the CEO level to see if NERC and stakeholders can get convergence on problems, issues and viable paths forward. It is hoped that this work can be completed through March.

3. Pending completion of this work, NERC intends to re-schedule the Standards Summit and hold it as a public forum. April was identified as a possible target date.

We should keep an eye to monitor how this evolves.

David

-----Original Message-----
From: Ben Li Associates [mailto:ben@benli.ca]
Sent: Saturday, January 14, 2012 8:19 PM
To: 'Guy V. Zito'; KIGUEL David; 'Gerard J. Dunbar'; carol.sedewitz@us.ngrid.com; diane_barney@dps.state.ny.us
Subject: RE: NERC: Standards Development Process and Cybersecurity Standards Forum

I agree. At the SC meeting, most asks for a root cause analysis to identify

what is really wrong, if any, with the current process. Until this is done, any proposal for a revised or completely revamp process is inappropriate.

Ben

-----Original Message-----
From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: Saturday, January 14, 2012 8:16 PM
To: david.kiguel@HydroOne.com; ben@benli.ca; Gerard J. Dunbar; carol.sedewitz@us.ngrid.com; diane_barney@dps.state.ny.us
Subject: RE: NERC: Standards Development Process and Cybersecurity Standards Forum

Ben,

Yes David is correct. Imperfect as the current process for developing standards is, the industry is comfortable with it and feels like they can participate sufficiently and their opinions considered. Some of what is being envisioned will not be embraced by the industry in my opinion. I would be more than happy to bounce anything off the RSC but at this point don't know where to begin or what processes will make the "first cut" .

Thanks,

Guy V. Zito

Assistant Vice President-Standards

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1040 Avenue of the Americas, 10 th Floor

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_____

From: david.kiguel@HydroOne.com [david.kiguel@HydroOne.com]

Sent: Saturday, January 14, 2012 1:32 PM

To: ben@benli.ca; Guy V. Zito; Gerard J. Dunbar; carol.sedewitz@us.ngrid.com; diane_barney@dps.state.ny.us

Subject: Re: NERC: Standards Development Process and Cybersecurity Standards Forum

Thank you Ben,

This is an interesting development; a setback for Mr Cauley who personally committed in November to both the MRC and FERC to hold this event.

To me, the SC reaction was fundamental for this development.

The current process, though not perfect, is a success story thanks to the industry, and NERC and regions staff.

David Kiguel

Sent from my BlackBerry. Please excuse my typos.

From: Ben Li Associates [mailto:ben@benli.ca]

Sent: Saturday, January 14, 2012 11:03 AM

To: KIGUEL David; 'Guy V. Zito' <gzito@npcc.org>; 'Gerard J. Dunbar' <gdunbar@npcc.org>; carol.sedewitz@us.ngrid.com <carol.sedewitz@us.ngrid.com>; diane_barney@dps.state.ny.us <diane_barney@dps.state.ny.us>

Subject: FW: NERC: Standards Development Process and Cybersecurity Standards Forum

Interesting development.

Heard some noises about this at the SC meeting, but didn't relay them to you as there wasn't anything concrete.

Don't know the rationale behind it but the SC's concerns and its general view that the proposed process is a non-starter might have been a factor in Cauley's decision to postpone the summit meeting.

Ben

From: Stacia-Ann Chambers [mailto:Stacia-Ann.Chambers@nerc.net]

Sent: Friday, January 13, 2012 09:35 PM

To: trades <trades@listserv.nerc.com<mailto:trades@listserv.nerc.com>>

Subject: NERC: Standards Development Process and Cybersecurity Standards Forum

[cid:image004.jpg@01CCD2AC.29472CC0]

Announcement

Standards Development Process and Cybersecurity Standards Forum

January 13, 2012

Ladies and Gentlemen:

After receiving thoughtful feedback from the industry, NERC is postponing the February 28-29 forum on the Standards Development Process and Cybersecurity Standards. In the interim, we will reach out to industry stakeholders to further develop the issues and alternatives.

For more information or assistance, please contact Mike Moon<mailto:michael.moon@nerc.net> or Herb Schrayshuen<mailto:herb.schrayshuen@nerc.net> (via email).

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[cid:image005.jpg@01CCD2AC.29472CC0]

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Compliance is required with all regulatory authority approved Reliability Standards whether or not included in the subset of reliability standards and requirements designated to be audited in the NERC implementation plan. All requirements are subject to a possible CVI, Self-Report, or Complaint.

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
			RESOURCE AND DEMAND BALANCING												
BAL-001-0.1a	R1.		Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control	MEDIUM	BA						M				
BAL-001-0.1a	R2.		Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a	MEDIUM	BA						M				
BAL-001-0.1a	R3.		Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and	LOWER	BA										
BAL-001-0.1a	R4.		Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance	LOWER	BA										
BAL-002-0	R1.		Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied	HIGH	BA, RSG			x			Q				
BAL-002-0		R1.1.	A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the	HIGH	BA, RSG			x			Q				
BAL-002-0	R2.		Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:	MEDIUM	RRO, RSG			x			Q				
BAL-002-0		R2.1.	The minimum reserve requirement for the group.	HIGH	RRO, RSG			x			Q				
BAL-002-0		R2.2.	Its allocation among members.	LOWER	RRO, RSG			x			Q				
BAL-002-0		R2.3.	The permissible mix of Operating Reserve - Spinning and Operating Reserve - Supplemental that may be included in Contingency Reserve.	LOWER	RRO, RSG			x			Q				
BAL-002-0		R2.4.	The procedure for applying Contingency Reserve in practice.	LOWER	RRO, RSG			x			Q				
BAL-002-0		R2.5.	The limitations, if any, upon the amount of interruptible load that may be included.	LOWER	RRO, RSG			x			Q				
BAL-002-0		R2.6.	The same portion of resource capacity (e.g., reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by	MEDIUM	RRO, RSG			x			Q				
BAL-002-0	R3.		Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.	HIGH	BA, RSG	x					Q				

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
BAL-002-0		R3.1.	As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single	HIGH	BA, RSG	x					Q				
BAL-002-0	R4.		A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for	MEDIUM	BA, RSG			x			Q				
BAL-002-0		R4.1.	A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE	MEDIUM	BA, RSG			x			Q				
BAL-002-0		R4.2.	The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs	No VRF Assigned	BA, RSG			x			Q				
BAL-002-0	R5.		Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition	LOWER	RSG			x			Q				
BAL-002-0		R5.1.	The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or	No VRF Assigned	RSG			x			Q				
BAL-002-0		R5.2.	The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its	No VRF Assigned	RSG			x			Q				
BAL-002-0	R6.		A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period	MEDIUM	BA, RSG			x			Q				
BAL-002-0		R6.1.	The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.	No VRF Assigned	BA, RSG			x			Q				
BAL-002-0		R6.2.	The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection	No VRF Assigned	BA, RSG			x			Q				
BAL-002-1 (effective 4/1/2012)	R1.		Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied	HIGH	BA, RSG										
BAL-002-1 (effective 4/1/2012)		R1.1.	A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the	HIGH	BA, RSG										
BAL-002-1 (effective 4/1/2012)	R2.		Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:	MEDIUM	RRO, RSG										
BAL-002-1 (effective 4/1/2012)		R2.1.	The minimum reserve requirement for the group.	HIGH	RRO, RSG										
BAL-002-1 (effective 4/1/2012)		R2.2.	Its allocation among members.	LOWER	RRO, RSG										
BAL-002-1 (effective 4/1/2012)		R2.3.	The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.	LOWER	RRO, RSG										
BAL-002-1 (effective 4/1/2012)		R2.4.	The procedure for applying Contingency Reserve in practice.	LOWER	RRO, RSG										

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
BAL-002-1 (effective 4/1/2012)		R2.5.	The limitations, if any, upon the amount of interruptible load that may be included.	LOWER	RRO, RSG										
BAL-002-1 (effective 4/1/2012)		R2.6.	The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by	MEDIUM	RRO, RSG										
BAL-002-1 (effective 4/1/2012)	R3.		Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.	HIGH	BA, RSG										
BAL-002-1 (effective 4/1/2012)		R3.1.	As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single	HIGH	BA, RSG										
BAL-002-1 (effective 4/1/2012)	R4.		A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for	MEDIUM	BA, RSG										
BAL-002-1 (effective 4/1/2012)		R4.1.	A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE	MEDIUM	BA, RSG										
BAL-002-1 (effective 4/1/2012)		R4.2.	The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.	No VRF Assigned	BA, RSG										
BAL-002-1 (effective 4/1/2012)	R5.		Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition	LOWER	RSG										
BAL-002-1 (effective 4/1/2012)		R5.1.	The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its	No VRF Assigned	RSG										
BAL-002-1 (effective 4/1/2012)		R5.2.	The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its	No VRF Assigned	RSG										
BAL-002-1 (effective 4/1/2012)	R6.		A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period	MEDIUM	BA, RSG										
BAL-002-1 (effective 4/1/2012)		R6.1.	The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.	No VRF Assigned	BA, RSG										
BAL-002-1 (effective 4/1/2012)		R6.2.	The default Contingency Reserve Restoration Period is 90 minutes.	No VRF Assigned	BA, RSG										
BAL-003-0.1b	R1.		Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency	LOWER	BA			x							
BAL-003-0.1b		R1.1.	The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the	LOWER	BA			x							
BAL-003-0.1b		R1.2.	Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.	LOWER	BA			x			A	ER			
BAL-003-0.1b	R2.		Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's	MEDIUM	BA		x								

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
BAL-003-0.1b		R2.1.	The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation.	LOWER	BA		x								
BAL-003-0.1b		R2.2.	The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency	LOWER	BA		x								
BAL-003-0.1b	R3.		Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability. *See Standard for Approved Interpretation of R3 for WECC WATEC Procedure*	MEDIUM	BA			x							
BAL-003-0.1b	R4.		Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop	LOWER	BA			x							
BAL-003-0.1b		R4.1.	Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of	LOWER	BA			x							
BAL-003-0.1b		R4.2.	The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop	LOWER	BA			x							
BAL-003-0.1b	R5.		Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's	MEDIUM	BA			x							
BAL-003-0.1b		R5.1.	Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation	MEDIUM	BA			x							
BAL-003-0.1b	R6.		A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the	MEDIUM	BA			x							
BAL-004-0	R1.		Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be	LOWER	RC										
BAL-004-0	R2.		The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error	LOWER	RC										
BAL-004-0	R3.		Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:	MEDIUM	BA										
BAL-004-0		R3.1.	The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or	LOWER	BA										
BAL-004-0		R3.2.	The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz	LOWER	BA										
BAL-004-0	R4.		Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error	LOWER	RC										
BAL-004-0		R4.1.	Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the	LOWER	BA							ER			

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BAL-005-0.1b	R1.		All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority	No VRF Assigned	GOP, LSE, TOP										
BAL-005-0.1b		R1.1.	Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered	MEDIUM	GOP										
BAL-005-0.1b		R1.2.	Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included	MEDIUM	TOP										
BAL-005-0.1b		R1.3.	Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a	MEDIUM	LSE										
BAL-005-0.1b	R2.		Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.	HIGH	BA										
BAL-005-0.1b	R3.		A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to	MEDIUM	BA										
BAL-005-0.1b	R4.		A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the	MEDIUM	BA										
BAL-005-0.1b	R5.		A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should	MEDIUM	BA										
BAL-005-0.1b	R6.		The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine	MEDIUM	BA										
BAL-005-0.1b	R7.		The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become	MEDIUM	BA										
BAL-005-0.1b	R8.		The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.	MEDIUM	BA										
BAL-005-0.1b		R8.1.	Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of	MEDIUM	BA										
BAL-005-0.1b	R9.		The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the	LOWER	BA										
BAL-005-0.1b		R9.1.	Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection	LOWER	BA										
BAL-005-0.1b	R10.		The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.	HIGH	BA										
BAL-005-0.1b	R11.		Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled	MEDIUM	BA										
BAL-005-0.1b	R12.		Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.	MEDIUM	BA										

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BAL-005-0.1b		R12.1.	Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon	LOWER	BA										
BAL-005-0.1b		R12.2.	Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are	MEDIUM	BA										
BAL-005-0.1b		R12.3.	Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more	MEDIUM	BA										
BAL-005-0.1b	R13.		Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the	LOWER	BA										
BAL-005-0.1b	R14.		The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of	LOWER	BA										
BAL-005-0.1b	R15.		The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's	LOWER	BA										
BAL-005-0.1b	R16.		The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data	MEDIUM	BA										
BAL-005-0.1b	R17.		Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing	MEDIUM	BA										
BAL-006-2	R1.		Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.	LOWER	BA										
BAL-006-2	R2.		Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The	LOWER	BA										
BAL-006-2	R3.		Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with	LOWER	BA										
BAL-006-2	R4.		Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly	LOWER	BA						M				
BAL-006-2		R4.1.	Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:	LOWER	BA						M				
BAL-006-2		R4.1.1.	The hourly values of Net Interchange Schedule.	LOWER	BA						M				
BAL-006-2		R4.1.2.	The hourly integrated megawatt-hour values of Net Actual Interchange.	LOWER	BA						M				
BAL-006-2		R4.2.	Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak	LOWER	BA						M				
BAL-006-2		R4.3.	A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating	LOWER	BA										

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BAL-006-2	R5.		Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the	LOWER	BA							ER			
			CRITICAL INFRASTRUCTURE PROTECTION												
CIP-001-2a	R1.		Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the	MEDIUM	BA, GOP, LSE, RC, TOP		x			A					X
CIP-001-2a	R2.		Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.	MEDIUM	BA, GOP, LSE, RC, TOP	x				A					X
CIP-001-2a	R3.		Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall provide its operating	MEDIUM	BA, GOP, LSE, RC, TOP	x				A					X
CIP-001-2a	R4.		Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall establish communications	MEDIUM	BA, GOP, LSE, RC, TOP		x			A					X
CIP-002-3	R1.		Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3		R1.1.	The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3		R1.2.	The risk-based assessment shall consider the following assets:	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3		R1.2.1.	Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3		R1.2.2.	Transmission substations that support the reliable operation of the Bulk Electric System.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3		R1.2.3.	Generation resources that support the reliable operation of the Bulk Electric System.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3		R1.2.4.	Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3		R1.2.5.	Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3		R1.2.6.	Special Protection Systems that support the reliable operation of the Bulk Electric System.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3		R1.2.7.	Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X

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CIP-002-3	R2.		Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3	R3.		Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3		R3.1.	The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3		R3.2.	The Cyber Asset uses a routable protocol within a control center; or,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3		R3.3.	The Cyber Asset is dial-up accessible	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-002-3	R4.		Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3	R1.		Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-003-3		R1.1.	The cyber security policy addresses the requirements in Standards CIP-002-3 through CIP-009-3, including provision for emergency situations.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-003-3		R1.2.	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-003-3		R1.3.	Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-003-3	R2.		Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3		R2.1.	The senior manager shall be identified by name, title, and date of designation.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3		R2.2.	Changes to the senior manager must be documented within thirty calendar days of the effective date.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3		R2.3.	Where allowed by Standards CIP-002-3 through CIP-009-3, the senior manager may delegate authority for specific actions to a named delegate or	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3		R2.4.	The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-003-3	R3.		Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3		R3.1.	Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					

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CIP-003-3		R3.2.	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3		R3.3.	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3	R4.		Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3		R4.1.	The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3		R4.2.	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3		R4.3.	The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-003-3	R5.		Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-003-3		R5.1.	The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-003-3		R5.1.1.	Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-003-3		R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3		R5.2.	The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-003-3		R5.3.	The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-003-3	R6.		Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-004-3	R1.		Awareness — The Responsible Entity shall establish, document, implement, and maintain a security awareness program to ensure personnel having	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3	R2.		Training — The Responsible Entity shall establish, document, implement, and maintain an annual cyber security training program for personnel having	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.1.	This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained prior to their	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.2.	Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004-3, and include, at a minimum,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					

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CIP-004-3		R2.2.1.	The proper use of Critical Cyber Assets;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.2.3.	The proper handling of Critical Cyber Asset information; and,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.2.4.	Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3		R2.3.	The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
CIP-004-3	R3.		Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-004-3		R3.1.	The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.)	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-004-3		R3.2.	The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-004-3		R3.3.	The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-004-3	R4.		Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-004-3		R4.1.	The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-004-3		R4.2.	The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a	R1.		Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R1.1.	Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R1.2.	For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R1.3.	Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R1.4.	Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X

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CIP-005-3a		R1.5.	Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R1.6.	The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a	R2.		Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R2.1.	These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R2.2.	At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R2.3.	The Responsible Entity shall implement and maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R2.4.	Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R2.5.	The required documentation shall, at least, identify and describe:	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a		R2.5.1.	The processes for access request and authorization.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a		R2.5.2.	The authentication methods.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a		R2.5.3.	The review process for authorization rights, in accordance with Standard CIP-004-3 Requirement R4.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a		R2.5.4.	The controls used to secure dial-up accessible connections.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a		R2.6.	Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a	R3.		Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R3.1.	For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R3.2.	Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a	R4.		Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X

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CIP-005-3a		R4.1.	A document identifying the vulnerability assessment process;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-005-3a		R4.2.	A review to verify that only ports and services required for operations at these access points are enabled;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R4.3.	The discovery of all access points to the Electronic Security Perimeter;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R4.4.	A review of controls for default accounts, passwords, and network management community strings;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R4.5.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a	R5.		Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R5.1.	The Responsible Entity shall ensure that all documentation required by Standard CIP-005-3 reflect current configurations and processes and shall review the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R5.2.	The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-005-3a		R5.3.	The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c	R1.		Physical Security Plan — The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.1.	All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall")	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.2.	Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.3.	Processes, tools, and procedures to monitor physical access to the perimeter(s).	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.4.	Appropriate use of physical access controls as described in Requirement R4 including visitor pass management, response to loss, and prohibition of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.5.	Review of access authorization requests and revocation of access authorization, in accordance with CIP-004-3 Requirement R4.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.6.	A visitor control program for visitors (personnel without authorized unescorted access to a Physical Security Perimeter), containing at a minimum the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c		R1.6.1.	Logs (manual or automated) to document the entry and exit of visitors, including the date and time, to and from Physical Security Perimeters.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X

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CIP-006-3c		R1.6.2.	Continuous escorted access of visitors within the Physical Security Perimeter.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c		R1.7.	Update of the physical security plan within thirty calendar days of the completion of any physical security system redesign or reconfiguration,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R1.8.	Annual review of the physical security plan.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c	R2.		Protection of Physical Access Control Systems — Cyber Assets that authorize and/or log access to the Physical Security Perimeter(s), exclusive of	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R2.1.	Be protected from unauthorized physical access.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R2.2.	Be afforded the protective measures specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c	R3.		Protection of Electronic Access Control Systems — Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c	R4.		Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c	R5.		Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c	R6.		Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c	R7.		Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c	R8.		Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-006-3c		R8.1.	Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c		R8.2.	Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R8.1.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-006-3c		R8.3.	Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R1.		Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R1.1.	The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X

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CIP-007-3		R1.2.	The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R1.3.	The Responsible Entity shall document test results.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R2.		Ports and Services — The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R2.1.	The Responsible Entity shall enable only those ports and services required for normal and emergency operations.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R2.2.	The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R2.3.	In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R3.		Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R3.1.	The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R3.2.	The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R4.		Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R4.1.	The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R4.2.	The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R5.		Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.1.1.	The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.1.2.	The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.1.3.	The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X

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CIP-007-3		R5.2.	The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.2.1.	The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.2.2.	The Responsible Entity shall identify those individuals with access to shared accounts.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.2.3.	Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.3.	At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.3.1.	Each password shall be a minimum of six characters.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.3.2.	Each password shall consist of a combination of alpha, numeric, and “special” characters.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R5.3.3.	Each password shall be changed at least annually, or more frequently based on risk.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R6.		Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R6.1.	The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R6.2.	The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R6.3.	The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R6.4.	The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R6.5.	The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R7.		Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R7.1.	Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R7.2.	Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X

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CIP-007-3		R7.3.	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R8.		Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R8.1.	A document identifying the vulnerability assessment process;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-007-3		R8.2.	A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R8.3.	A review of controls for default accounts; and,	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3		R8.4.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-007-3	R9.		Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-3 at least annually.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-008-3	R1.		Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan and implement the plan in	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-008-3		R1.1.	Procedures to characterize and classify events as reportable Cyber Security Incidents.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-008-3		R1.2.	Response actions, including roles and responsibilities of Cyber Security Incident response teams, Cyber Security Incident handling procedures, and	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-008-3		R1.3.	Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The Responsible Entity must	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-008-3		R1.4.	Process for updating the Cyber Security Incident response plan within thirty calendar days of any changes.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-008-3		R1.5.	Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-008-3		R1.6.	Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the Cyber Security Incident response plan can range from a	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-008-3	R2.		Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-009-3	R1.		Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-009-3		R1.1.	Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X

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CIP-009-3		R1.2.	Define the roles and responsibilities of responders.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC	x				A					X
CIP-009-3	R2.		Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-009-3	R3.		Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident.	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC			x		A					
CIP-009-3	R4.		Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					X
CIP-009-3	R5.		Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is	Pending	BA, GO, GOP, IA, LSE, RC, RE, TO, TOP, TSP, NERC		x			A					
			COMMUNICATIONS												
COM-001-1.1	R1.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:	HIGH	BA, RC, TOP	x				A					X
COM-001-1.1		R1.1.	Internally.	HIGH	BA, RC, TOP	x				A					X
COM-001-1.1		R1.2.	Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.	HIGH	BA, RC, TOP	x				A					X
COM-001-1.1		R1.3.	With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.	HIGH	BA, RC, TOP	x				A					X
COM-001-1.1		R1.4.	Where applicable, these facilities shall be redundant and diversely routed.	HIGH	BA, RC, TOP	x				A					X
COM-001-1.1	R2.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.	MEDIUM	BA, RC, TOP	x				A					X
COM-001-1.1	R3.		Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.	LOWER	BA, RC, TOP		x			A					X

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COM-001-1.1	R4.		Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.	MEDIUM	BA, RC, TOP			x		A					X
COM-001-1.1	R5.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.	LOWER	BA, RC, TOP		x			A					X
COM-001-1.1	R6.		Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, "NERCNet Security Policy."	LOWER	NERC_Net Users			x		A					X
COM-002-2	R1.		Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.	HIGH	BA, GOP, TOP			x		A					X
COM-002-2		R1.1.	Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.	HIGH	BA, TOP			x		A					X
COM-002-2	R2.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall	MEDIUM	BA, RC, TOP	x				A					X
			EMERGENCY PREPAREDNESS AND OPERATIONS												
EOP-001-0b	R1.		Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for	HIGH	BA			x							
EOP-001-0b (R2 retired 11/30/2011)	R2.		The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.	MEDIUM	TOP										X

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EOP-001-0b	R3.		Each Transmission Operator and Balancing Authority shall:	MEDIUM	BA, TOP	x				A					X
EOP-001-0b		R3.1.	Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.	MEDIUM	BA, TOP	x				A					X
EOP-001-0b		R3.2.	Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.	MEDIUM	BA, TOP	x				A					X
EOP-001-0b		R3.3.	Develop, maintain, and implement a set of plans for load shedding.	MEDIUM	BA, TOP	x				A					X
EOP-001-0b		R3.4.	Develop, maintain, and implement a set of plans for system restoration.	MEDIUM	BA, TOP	x				A					
EOP-001-0b	R4.		Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a	MEDIUM	BA, TOP		x								
EOP-001-0b		R4.1.	Communications protocols to be used during emergencies.	MEDIUM	BA, TOP		x								
EOP-001-0b		R4.2.	A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one	MEDIUM	BA, TOP		x								
EOP-001-0b		R4.3.	The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.	MEDIUM	BA, TOP		x								
EOP-001-0b		R4.4.	Staffing levels for the emergency.	MEDIUM	BA, TOP		x								
EOP-001-0b	R5.		Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency	MEDIUM	BA, TOP			x		A					X
EOP-001-0b	R6.		The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and	MEDIUM	BA, TOP			x							
EOP-001-0b	R7.		The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing	MEDIUM	BA, TOP		x								
EOP-001-0b		R7.1.	The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.	MEDIUM	BA, TOP		x								
EOP-001-0b		R7.2.	The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers	MEDIUM	BA, TOP		x								
EOP-001-0b		R7.3.	The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or	MEDIUM	BA, TOP	x									
EOP-001-0b		R7.4.	The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal	MEDIUM	BA, TOP	x									

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EOP-002-3	R1.		Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to	HIGH	BA, RC			x							
EOP-002-3	R2.		Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan, , to reduce	HIGH	BA			x							
EOP-002-3	R3.		A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to	HIGH	BA			x							
EOP-002-3	R4.		A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available	HIGH	BA			x							
EOP-002-3	R5.		A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective	HIGH	BA			x							
EOP-002-3	R6.		If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to	HIGH	BA			x							
EOP-002-3		R6.1.	Loading all available generating capacity.	HIGH	BA			x							
EOP-002-3		R6.2.	Deploying all available operating reserve.	HIGH	BA			x							
EOP-002-3		R6.3.	Interrupting interruptible load and exports.	HIGH	BA			x							
EOP-002-3		R6.4.	Requesting emergency assistance from other Balancing Authorities.	HIGH	BA			x							
EOP-002-3		R6.5.	Declaring an Energy Emergency through its Reliability Coordinator; and	HIGH	BA			x							
EOP-002-3		R6.6.	Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.	HIGH	BA			x							
EOP-002-3	R7.		Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve	HIGH	BA	x				A					X
EOP-002-3		R7.1.	Manually shed firm load without delay to return its ACE to zero; and	HIGH	BA	x				A					X
EOP-002-3		R7.2.	Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency Alert Levels."	HIGH	BA	x				A					X
EOP-002-3	R8.		A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency	HIGH	RC	x				A					X
EOP-002-3	R9.		When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network	HIGH	LSE, RC			x							

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EOP-002-3		R9.1.	The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-	HIGH	LSE			x							
EOP-002-3		R9.2.	The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission	HIGH	RC			x				ER			
EOP-002-3		R9.3.	The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority	LOWER	RC			x				ER			
EOP-002-3		R9.4.	The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system	LOWER	RC			x				ER			
EOP-003-1	R1.		After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	HIGH	BA, TOP		x								
EOP-003-1	R2.		Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.	HIGH	BA, TOP			x							X
EOP-003-1	R3.		Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.	HIGH	BA, TOP			x							X
EOP-003-1	R4.		A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.	HIGH	BA, TOP			x							X
EOP-003-1	R5.		A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss	HIGH	BA, TOP			x							
EOP-003-1	R6.		After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to	HIGH	BA, TOP			x							
EOP-003-1	R7.		The Transmission Operator and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions	HIGH	BA, TOP			x							
EOP-003-1	R8.		Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time	HIGH	BA, TOP		x								X
EOP-004-1	R1.		Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final	LOWER	RRO			x							
EOP-004-1	R2.		A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall promptly analyze Bulk	MEDIUM	BA, GOP, LSE, RC, TOP			x							

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EOP-004-1	R3.		A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity experiencing a reportable incident	LOWER	BA, GOP, LSE, RC, TOP	x						ER			
EOP-004-1		R3.1.	The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall submit within 24	LOWER	BA, GOP, LSE, RC, TOP			x				ER			
EOP-004-1		R3.2.	Applicable reporting forms are provided in Attachments 022-1 and 022-2.	No VRF Assigned	BA, GOP, LSE, RC, TOP			x							
EOP-004-1		R3.3.	Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written	LOWER	BA, GOP, LSE, RC, TOP			x				ER			
EOP-004-1		R3.4.	If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability	LOWER	BA, GOP, LSE, RC, TOP	x									
EOP-004-1	R4.		When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating	LOWER	RRO			x				ER			
EOP-004-1	R5.		The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being	LOWER	RRO			x				ER			
EOP-005-1	R1.		Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005 in developing a restoration plan.	MEDIUM	TOP		x			A					X
EOP-005-1	R2.		Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall	MEDIUM	TOP	x				A					X
EOP-005-1	R3.		Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.	MEDIUM	TOP		x			A					X
EOP-005-1	R4.		Each Transmission Operator shall coordinate its restoration plans with the Generator Owners and Balancing Authorities within its area, its Reliability	MEDIUM	TOP	x				A					X
EOP-005-1	R5.		Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration	MEDIUM	BA, TOP		x			A					X
EOP-005-1	R6.		Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan.	HIGH	BA, TOP	x				A					X
EOP-005-1	R7.		Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.	HIGH	BA, TOP		x			A					X

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EOP-005-1	R8.		Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional	HIGH	TOP		x			A					
EOP-005-1	R9.		The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the	MEDIUM	TOP		x			A					X
EOP-005-1	R10.		The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform	MEDIUM	TOP		x			A					X
EOP-005-1		R10.1.	The Transmission Operator shall perform this simulation or testing at least once every five years.	MEDIUM	TOP	x				A					X
EOP-005-1	R11.		Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and	HIGH	BA, TOP			x							
EOP-005-1		R11.1.	The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent	MEDIUM	BA, TOP			x							
EOP-005-1		R11.2.	The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal,	HIGH	BA, TOP			x							
EOP-005-1		R11.3.	The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between	HIGH	BA			x							
EOP-005-1		R11.4.	The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.	HIGH	TOP	x									
EOP-005-1		R11.5.	The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:	MEDIUM	TOP			x							
EOP-005-1		R11.5.1.	Voltage, frequency, and phase angle permit.	HIGH	TOP			x							
EOP-005-1		R11.5.2.	The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across	HIGH	TOP			x							
EOP-005-1		R11.5.3.	Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.	MEDIUM	TOP			x							
EOP-005-1		R11.5.4.	Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.	HIGH	TOP			x							
EOP-006-1	R1.		Each Reliability Coordinator shall be aware of the restoration plan of each Transmission Operator in its Reliability Coordinator Area in accordance with	MEDIUM	RC			x							
EOP-006-1	R2.		The Reliability Coordinator shall monitor restoration progress and coordinate any needed assistance.	HIGH	RC	x									
EOP-006-1	R3.		The Reliability Coordinator shall have a Reliability Coordinator Area restoration plan that provides coordination between individual Transmission Operator	MEDIUM	RC		x								

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EOP-006-1	R4.		The Reliability Coordinator shall serve as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and	MEDIUM	RC			x							
EOP-006-1	R5.		Reliability Coordinators shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to	HIGH	RC	x									
EOP-006-1	R6.		The Reliability Coordinator shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its	MEDIUM	RC			x							
EOP-008-0	R1.		Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its	HIGH	BA, RC, TOP	x				A					X
EOP-008-0		R1.1.	The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.	MEDIUM	BA, RC, TOP	x									X
EOP-008-0		R1.2.	The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules	MEDIUM	BA, RC, TOP			x							X
EOP-008-0		R1.3.	The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and	MEDIUM	BA, RC, TOP	x				A					X
EOP-008-0		R1.4.	The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.	HIGH	BA, RC, TOP		x								X
EOP-008-0		R1.5.	The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.	MEDIUM	BA, RC, TOP	x				A					X
EOP-008-0		R1.6.	The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the	MEDIUM	BA, RC, TOP	x				A					X
EOP-008-0		R1.7.	The plan shall be reviewed and updated annually.	MEDIUM	BA, RC, TOP			x							X
EOP-008-0		R1.8.	Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.	MEDIUM	BA, RC, TOP			x							X
EOP-009-0	R1.		The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in	MEDIUM	GOP										
EOP-009-0	R2.		The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating	LOWER	GO, GOP						A				
			FACILITIES DESIGN, CONNECTIONS AND MAINTENANCE												
FAC-001-0	R1.		The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability	MEDIUM	TO			x							
FAC-001-0		R1.1.	Generation facilities,	MEDIUM	TO			x							

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FAC-001-0		R1.2.	Transmission facilities, and	MEDIUM	TO			x							
FAC-001-0		R1.3.	End-user facilities	MEDIUM	TO			x							
FAC-001-0	R2.		The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:	MEDIUM	TO	x									
FAC-001-0		R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM	TO	x									
FAC-001-0		R2.1.1.	Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.	MEDIUM	TO			x							
FAC-001-0		R2.1.2.	Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as	MEDIUM	TO	x									
FAC-001-0		R2.1.3.	Voltage level and MW and MVAR capacity or demand at point of connection.	MEDIUM	TO			x							
FAC-001-0		R2.1.4.	Breaker duty and surge protection.	MEDIUM	TO		x								
FAC-001-0		R2.1.5.	System protection and coordination.	MEDIUM	TO	x									
FAC-001-0		R2.1.6.	Metering and telecommunications.	MEDIUM	TO			x							
FAC-001-0		R2.1.7.	Grounding and safety issues.	MEDIUM	TO			x							
FAC-001-0		R2.1.8.	Insulation and insulation coordination.	MEDIUM	TO			x							
FAC-001-0		R2.1.9.	Voltage, Reactive Power, and power factor control.	MEDIUM	TO			x							
FAC-001-0		R2.1.10.	Power quality impacts.	MEDIUM	TO			x							
FAC-001-0		R2.1.11.	Equipment Ratings.	MEDIUM	TO			x							
FAC-001-0		R2.1.12.	Synchronizing of facilities.	MEDIUM	TO			x							
FAC-001-0		R2.1.13.	Maintenance coordination.	MEDIUM	TO			x							

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FAC-001-0		R2.1.14.	Operational issues (abnormal frequency and voltages).	MEDIUM	TO	x									
FAC-001-0		R2.1.15.	Inspection requirements for existing or new facilities.	MEDIUM	TO			x							
FAC-001-0		R2.1.16.	Communications and procedures during normal and emergency operating conditions.	MEDIUM	TO		x								
FAC-001-0	R3.		The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make	MEDIUM	TO			x							
FAC-002-1	R1.		The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission	MEDIUM	DP, GO, LSE, TO	x									
FAC-002-1		R1.1.	Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.	MEDIUM	DP, GO, LSE, TO		x								
FAC-002-1		R1.2.	Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and	MEDIUM	DP, GO, LSE, TO		x								
FAC-002-1		R1.3.	Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the	MEDIUM	DP, GO, LSE, TO	x									
FAC-002-1		R1.4.	Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under both normal and	MEDIUM	DP, GO, LSE, TO		x								
FAC-002-1		R1.5.	Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated	MEDIUM	DP, GO, LSE, TO		x								
FAC-002-1	R2.		The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its	LOWER	DP, GO, LSE, PA, PC, TO, TP			x							
FAC-003-1	R1.		The Transmission owner shall prepare, and keep current, a formal transmission vegetation management (TVM). The TVMP shall include the Transmission	HIGH	TO	x				A					X
FAC-003-1		R1.1.	The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for	HIGH	TO	x				A					X
FAC-003-1		R1.2.	The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking	HIGH	TO	x				A					X
FAC-003-1		R1.2.1.	Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission	HIGH	TO	x				A					X
FAC-003-1		R1.2.2.	Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors	HIGH	TO	x				A					X
FAC-003-1		R1.2.2.1.	Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground	HIGH	TO	x				A					X

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FAC-003-1		R1.2.2.2.	Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages,	HIGH	TO	x				A					X
FAC-003-1		R1.3.	All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission	HIGH	TO	x				A					X
FAC-003-1		R1.4.	Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies	HIGH	TO	x				A					X
FAC-003-1		R1.5.	Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an	HIGH	TO	x				A					X
FAC-003-1	R2.		The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan	HIGH	TO	x				A					X
FAC-003-1	R3.		The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission	LOWER	TO			x			Q				
FAC-003-1		R3.1.	Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number	LOWER	TO			x			Q				
FAC-003-1		R3.2.	The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1)	LOWER	TO			x			Q				
FAC-003-1		R3.3.	The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s)	LOWER	TO			x			Q				
FAC-003-1		R3.4.	An outage shall be categorized as one of the following:	LOWER	TO			x			Q				
FAC-003-1		R3.4.1.	Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW.	LOWER	TO			x			Q				
FAC-003-1		R3.4.2.	Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW.	LOWER	TO			x			Q				
FAC-003-1		R3.4.3.	Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.	LOWER	TO			x			Q				
FAC-003-1	R4.		The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as	LOWER	RRO			x			Q				
FAC-008-1	R1.		The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings	LOWER	GO, TO		x			A					X
FAC-008-1		R1.1.	A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.2.	The method by which the Rating (of major BES equipment that comprises a Facility) is determined.	MEDIUM	GO, TO		x			A					X

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FAC-008-1		R1.2.1.	The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.2.2.	The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.3.	Consideration of the following:	LOWER	GO, TO		x			A					X
FAC-008-1		R1.3.1.	Ratings provided by equipment manufacturers.	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.3.2.	Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.3.3.	Ambient conditions.	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.3.4.	Operating limitations.	MEDIUM	GO, TO		x			A					X
FAC-008-1		R1.3.5.	Other assumptions.	LOWER	GO, TO		x			A					X
FAC-008-1	R2.		The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.	LOWER	GO, TO			x							X
FAC-008-1	R3.		If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a	LOWER	GO, TO			x							
FAC-009-1	R1.		The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the	MEDIUM	GO, TO	x				A					X
FAC-009-1	R2.		The Transmission Owner and Generator Owner shall each provide Facility Ratings 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 Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.	MEDIUM	GO, TO	x									X
FAC-010-2.1	R1.		The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology	LOWER	PA, PC										

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FAC-010-2.1		R1.1.	Be applicable for developing SOLs used in the planning horizon.	LOWER	PA, PC										
FAC-010-2.1		R1.2.	State that SOLs shall not exceed associated Facility Ratings.	LOWER	PA, PC										
FAC-010-2.1		R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	LOWER	PA, PC										
FAC-010-2.1	R2.		The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	No VRF Assigned	PA, PC										
FAC-010-2.1		R2.1.	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and	HIGH	PA, PC										
FAC-010-2.1		R2.2.	Following the single Contingencies1 identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and	HIGH	PA, PC										
FAC-010-2.1		R2.2.1.	Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt	MEDIUM	PA, PC										
FAC-010-2.1		R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	MEDIUM	PA, PC										
FAC-010-2.1		R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	MEDIUM	PA, PC										
FAC-010-2.1		R2.3.	Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	MEDIUM	PA, PC										
FAC-010-2.1		R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted	MEDIUM	PA, PC										
FAC-010-2.1		R2.3.2.	System reconfiguration through manual or automatic control or protection actions.	MEDIUM	PA, PC										
FAC-010-2.1		R2.4.	To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the	MEDIUM	PA, PC										
FAC-010-2.1		R2.5.	Starting with all facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall	MEDIUM	PA, PC										
FAC-010-2.1		R2.6.	In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in	MEDIUM	PA, PC										
FAC-010-2.1		R2.6.1.	Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the	MEDIUM	PA, PC										
FAC-010-2.1	R3.		The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied	LOWER	PA, PC										

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FAC-010-2.1		R3.1.	Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would	LOWER	PA, PC										
FAC-010-2.1		R3.2.	Selection of applicable Contingencies.	LOWER	PA, PC										
FAC-010-2.1		R3.3.	Level of detail of system models used to determine SOLs.	LOWER	PA, PC										
FAC-010-2.1		R3.4.	Allowed uses of Special Protection Systems or Remedial Action Plans.	MEDIUM	PA, PC										
FAC-010-2.1		R3.5.	Anticipated transmission system configuration, generation dispatch and Load level.	LOWER	PA, PC										
FAC-010-2.1		R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated	MEDIUM	PA, PC										
FAC-010-2.1	R4.		The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:	LOWER	PA, PC										
FAC-010-2.1		R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	LOWER	PA, PC										
FAC-010-2.1		R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	LOWER	PA, PC										
FAC-010-2.1		R4.3.	Each Transmission Planner that works in the Planning Authority's Planning Authority Area.	LOWER	PA, PC										
FAC-010-2.1	R5.		If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a	LOWER	PA, PC										
FAC-011-2	R1.		The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.	LOWER	RC										
FAC-011-2		R1.1.	Be applicable for developing SOLs used in the operations horizon.	LOWER	RC										
FAC-011-2		R1.2.	State that SOLs shall not exceed associated Facility Ratings.	LOWER	RC										
FAC-011-2		R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	LOWER	RC										
FAC-011-2	R2.		The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	No VRF Assigned	RC										
FAC-011-2		R2.1.	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and	HIGH	RC										

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FAC-011-2		R2.2.	Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and	HIGH	RC										
FAC-011-2		R2.2.1.	Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	MEDIUM	RC										
FAC-011-2		R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	MEDIUM	RC										
FAC-011-2		R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	MEDIUM	RC										
FAC-011-2		R2.3.	In determining the system's response to a single Contingency, the following shall be acceptable:	MEDIUM	RC										
FAC-011-2		R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted	MEDIUM	RC										
FAC-011-2		R2.3.2.	Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-	MEDIUM	RC										
FAC-011-2		R2.3.3.	System reconfiguration through manual or automatic control or protection actions.	MEDIUM	RC										
FAC-011-2		R2.4.	To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the	MEDIUM	RC										
FAC-011-2	R3.		The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability	MEDIUM	RC										
FAC-011-2		R3.1.	Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that	MEDIUM	RC										
FAC-011-2		R3.2.	Selection of applicable Contingencies	MEDIUM	RC										
FAC-011-2		R3.3.	A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with	MEDIUM	RC										
FAC-011-2		R3.3.1.	This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies	No VRF Assigned	RC										
FAC-011-2		R3.4.	Level of detail of system models used to determine SOLs.	LOWER	RC										
FAC-011-2		R3.5.	Allowed uses of Special Protection Systems or Remedial Action Plans.	MEDIUM	RC										
FAC-011-2		R3.6.	Anticipated transmission system configuration, generation dispatch and Load level	MEDIUM	RC										

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FAC-011-2		R3.7.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated	MEDIUM	RC										
FAC-011-2	R4.		The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a	LOWER	RC										
FAC-011-2		R4.1.	Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	LOWER	RC										
FAC-011-2		R4.2.	Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	LOWER	RC										
FAC-011-2		R4.3.	Each Transmission Operator that operates in the Reliability Coordinator Area.	LOWER	RC										
FAC-011-2	R5.		If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a	LOWER	RC										
FAC-013-1	R1.		The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its	MEDIUM	PA, PC, RC										
FAC-013-1	R2.		The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a	MEDIUM	PA, PC, RC										
FAC-013-1		R2.1.	The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and	MEDIUM	RC										
FAC-013-1		R2.2.	The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the	MEDIUM	PA, PC										
FAC-014-2	R1.		The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are	MEDIUM	RC					A					
FAC-014-2	R2.		The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are	MEDIUM	RC, TOP					A					
FAC-014-2	R3.		The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.	MEDIUM	PA, PC					A					
FAC-014-2	R4.		The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's	MEDIUM	PA, PC, TP					A					
FAC-014-2	R5.		The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-	HIGH	PA, PC, RC, TP					A					
FAC-014-2		R5.1.	The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability	HIGH	RC					A					
FAC-014-2		R5.1.1.	Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.	MEDIUM	RC					A					

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FAC-014-2		R5.1.2.	The value of the IROL and its associated Tv.	MEDIUM	RC					A					
FAC-014-2		R5.1.3.	The associated Contingency(ies).	MEDIUM	RC					A					
FAC-014-2		R5.1.4.	The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	MEDIUM	RC					A					
FAC-014-2		R5.2.	The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion	MEDIUM	TOP					A					
FAC-014-2		R5.3.	The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission	MEDIUM	PA, PC					A					
FAC-014-2		R5.4.	The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission	MEDIUM	TP					A					
FAC-014-2	R6.		The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.	MEDIUM	PA, PC					A					
FAC-014-2		R6.1.	The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the	MEDIUM	PA, PC					A					
FAC-014-2		R6.2.	If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability	MEDIUM	PA, PC					A					
			INTERCHANGE SCHEDULING AND COORDINATION												
INT-001-3	R1.		The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:	LOWER	PSE							ER			
INT-001-3		R1.1.	All Dynamic Schedules at the expected average MW profile for each hour.	LOWER	PSE							ER			
INT-001-3	R2.		The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:	LOWER	BA							ER			
INT-001-3		R2.1.	If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.	LOWER	BA							ER			
INT-001-3		R2.2.	For each bilateral Inadvertent Interchange payback.	LOWER	BA							ER			
INT-003-3	R1.		Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing	MEDIUM	BA							ER			
INT-003-3		R1.1.	The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including:	LOWER	BA							ER			

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INT-003-3		R1.1.1.	Interchange Schedule start and end time.	LOWER	BA							ER			
INT-003-3		R1.1.2.	Energy profile.	LOWER	BA							ER			
INT-003-3		R1.2.	If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall	MEDIUM	BA							ER			
INT-004-2	R1.		At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the	LOWER	BA, PSE, RC, TOP										
INT-004-2	R2.		The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available	LOWER	PSE										
INT-004-2		R2.1.	The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile	LOWER	PSE										
INT-004-2		R2.2.	The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy	LOWER	PSE										
INT-004-2		R2.3.	A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the	LOWER	PSE										
INT-005-3	R1.		Prior to the expiration of the time period defined in the Timing Table, Column A, the Interchange Authority shall distribute the Arranged Interchange information for	MEDIUM	IA										
INT-005-3		R1.1.	When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority	MEDIUM	IA										
INT-006-3	R1.		Prior to the expiration of the reliability assessment period defined in the Timing Table, Column B, the Balancing Authority and Transmission Service	LOWER	BA, TSP										
INT-006-3		R1.1.	Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:	LOWER	BA										
INT-006-3		R1.1.1.	Energy profile (ability to support the magnitude of the Interchange).	LOWER	BA										
INT-006-3		R1.1.2.	Ramp (ability of generation maneuverability to accommodate).	LOWER	BA										
INT-006-3		R1.1.3.	Scheduling path (proper connectivity of Adjacent Balancing Authorities).	LOWER	BA										
INT-006-3		R1.2.	Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged	LOWER	TSP										
INT-007-1	R1.		The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by	LOWER	IA										

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INT-007-1		R1.1.	Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).	LOWER	IA										
INT-007-1		R1.2.	All reliability entities involved in the Arranged Interchange are currently in the NERC registry.	LOWER	IA										
INT-007-1		R1.3.	The following are defined:	LOWER	IA										
INT-007-1		R1.3.1.	Generation source and load sink.	LOWER	IA										
INT-007-1		R1.3.2.	Megawatt profile.	LOWER	IA										
INT-007-1		R1.3.3.	Ramp start and stop times.	LOWER	IA										
INT-007-1		R1.3.4.	Interchange duration.	LOWER	IA										
INT-007-1		R1.4.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange	LOWER	IA										
INT-008-3	R1.		Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including	LOWER	IA										
INT-008-3		R1.1.	For Confirmed Interchange, the Interchange Authority shall also communicate:	LOWER	IA										
INT-008-3		R1.1.1.	Start and stop times, ramps, and megawatt profile to Balancing Authorities.	LOWER	IA										
INT-008-3		R1.1.2.	Necessary Interchange information to NERC-identified reliability analysis services.	LOWER	IA										
INT-009-1	R1.		The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.	MEDIUM	BA										
INT-010-1	R1.		The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged	LOWER	BA										
INT-010-1	R2.		For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the	LOWER	RC										
INT-010-1	R3.		For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall	LOWER	RC										
			INTERCONNECTION RELIABILITY OPERATIONS AND COORDINATION												

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IRO-001-1.1	R1.		Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously	HIGH	RRO										
IRO-001-1.1	R2.		The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	HIGH	RC										
IRO-001-1.1	R3.		The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing	HIGH	RC										
IRO-001-1.1	R4.		Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The	MEDIUM	RC										
IRO-001-1.1	R5.		The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	LOWER	RC										
IRO-001-1.1	R6.		The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	MEDIUM	RC										
IRO-001-1.1	R7.		The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System	HIGH	RC										
IRO-001-1.1	R8.		Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling	HIGH	BA, GOP, LSE, PSE, TOP, TSP										
IRO-001-1.1	R9.		The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of	HIGH	RC										
IRO-002-2	R1.		Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator	HIGH	RC		x								
IRO-002-2	R2.		Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other	MEDIUM	RC			x							
IRO-002-2	R3.		Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities,	MEDIUM	RC			x							
IRO-002-2	R4.		Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its	HIGH	RC			x							
IRO-002-2	R5.		Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could	HIGH	RC		x								
IRO-002-2	R6.		Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability,	HIGH	RC	x									
IRO-002-2	R7.		Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for	HIGH	RC			x							
IRO-002-2	R8.		Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability	HIGH	RC	x									

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IRO-003-2	R1.		Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its	HIGH	RC										
IRO-003-2	R2.		Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or	HIGH	RC										
IRO-004-2	R1.		Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on	HIGH	BA, TOP, TSP	x				A		ER			X
IRO-005-3a	R1.		Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:	Pending	RC		x			A					X
IRO-005-3a		R1.1.	Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and	Pending	RC		x			A					X
IRO-005-3a		R1.2.	Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations,	Pending	RC		x			A					X
IRO-005-3a		R1.3.	Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations,	Pending	RC		x			A					X
IRO-005-3a		R1.4.	System real and reactive reserves (actual versus required).	Pending	RC		x			A					X
IRO-005-3a		R1.5.	Capacity and energy adequacy conditions.	Pending	RC		x			A					X
IRO-005-3a		R1.6.	Current ACE for all its Balancing Authorities.	Pending	RC		x			A					X
IRO-005-3a		R1.7.	Current local or Transmission Loading Relief procedures in effect.	Pending	RC		x			A					X
IRO-005-3a		R1.8.	Planned generation dispatches.	Pending	RC		x			A					X
IRO-005-3a		R1.9.	Planned transmission or generation outages.	Pending	RC		x			A					X
IRO-005-3a		R1.10.	Contingency events.	Pending	RC		x			A					X
IRO-005-3a	R2.		Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided	Pending	RC		x			A					X
IRO-005-3a	R3.		Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast	Pending	RC	x				A					X
IRO-005-3a	R4.		The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	Pending	RC		x			A					X

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IRO-005-3a	R5.		Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to	Pending	BA, RC, TOP		x			A					X
IRO-005-3a	R6.		The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and	Pending	RC	x				A					X
IRO-005-3a	R7.		As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from	Pending	RC		x			A					X
IRO-005-3a	R8.		The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange	Pending	RC		x			A					X
IRO-005-3a	R9.		Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially	Pending	RC, TOP	x				A					X
IRO-005-3a	R10.		In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission	Pending	BA, GOP, LSE, PSE, TOP, TSP	x				A					X
IRO-005-3a	R11.		The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available	Pending	TSP			x		A					X
IRO-005-3a	R12.		Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its	Pending	RC	x				A					X
IRO-006-5	R1.		A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, with its authority and at its	HIGH	RC		x								
IRO-006-EAST-1	R1.		When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's TV, each Reliability	HIGH	RC		x								
IRO-006-EAST-1	R2.		To ensure operating entities are provided with information needed to maintain an awareness of changes to the Transmission System, when initiating	MEDIUM	RC		x								
IRO-006-EAST-1		R2.1.	A list of congestion management actions to be implemented, and	MEDIUM	RC		x								
IRO-006-EAST-1		R2.2.	One of the following TLR levels: TLR-1, TLR-2, TLR-3A, TLR-3B, TLR-4, TLR-5A, TLR-5B, TLR-6, TLR-0	MEDIUM	RC		x								
IRO-006-EAST-1	R3.		Upon the identification of the TLR level and a list of congestion management actions to be implemented, the Reliability Coordinator initiating this TLR procedure	MEDIUM	RC		x								
IRO-006-EAST-1		R3.1.	Notify all Reliability Coordinators in the Eastern Interconnection of the identified TLR level	MEDIUM	RC		x								
IRO-006-EAST-1		R3.2.	Communicate the list of congestion management actions to be implemented to 1.) all Reliability Coordinators in the Eastern Interconnection, and 2.) those	MEDIUM	RC		x								
IRO-006-EAST-1		R3.3.	Request that the congestion management actions identified in Requirement R2, Part 2.1 be implemented by:	MEDIUM	RC		x								

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IRO-006-EAST-1	R4.		Each Reliability Coordinator that receives a request as described in Requirement R3, Part 3.3. shall, within 15 minutes of receiving the request,	HIGH	RC		x								
IRO-006-WECC-1	R1.		Upon receiving a request of Step 4 or greater (see Attachment 1-IRO-006-WECC-1) from the Transmission Operator of a Qualified Transfer Path, the	MEDIUM	RC		x								
IRO-006-WECC-1	R2.		The Balancing Authorities shall approve curtailment requests to the schedules as submitted, implement alternative actions, or a combination there of that	MEDIUM	BA		x								
IRO-008-1	R1.		Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its	MEDIUM	RC										
IRO-008-1	R2.		Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is	HIGH	RC										
IRO-008-1	R3.		When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for	MEDIUM	RC										
IRO-009-1	R1.		For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability	MEDIUM	RC		x								
IRO-009-1	R2.		For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability	MEDIUM	RC		x								
IRO-009-1	R3.		When an assessment of actual or expected system conditions predicts that an IROL in its Reliability Coordinator Area will be exceeded, the Reliability	HIGH	RC			x							
IRO-009-1	R4.		When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without	HIGH	RC			x							
IRO-009-1	R5.		If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall,	HIGH	RC			x							
IRO-010-1a	R1.		The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring,	LOWER	RC										
IRO-010-1a		R1.1.	List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-	LOWER	RC										
IRO-010-1a		R1.2.	Mutually agreeable format.	LOWER	RC										
IRO-010-1a		R1.3.	Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational	LOWER	RC										
IRO-010-1a		R1.4.	Process for data provision when automated Real-Time system operating data is unavailable.	LOWER	RC										
IRO-010-1a	R2.		The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities	LOWER	RC										

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IRO-010-1a	R3.		Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and	MEDIUM	BA, GO, GOP, IA, LSE, RC, TO, TOP										
IRO-014-1	R1.		The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or	MEDIUM	RC		x								
IRO-014-1		R1.1.	These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:	LOWER	RC		x								
IRO-014-1		R1.1.1.	Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to	MEDIUM	RC		x								
IRO-014-1		R1.1.2.	Energy and capacity shortages.	MEDIUM	RC		x								
IRO-014-1		R1.1.3.	Planned or unplanned outage information.	MEDIUM	RC		x								
IRO-014-1		R1.1.4.	Voltage control, including the coordination of reactive resources for voltage control.	MEDIUM	RC		x								
IRO-014-1		R1.1.5.	Coordination of information exchange to support reliability assessments.	LOWER	RC		x								
IRO-014-1		R1.1.6.	Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	LOWER	RC		x								
IRO-014-1	R2.		Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make	LOWER	RC			x							
IRO-014-1		R2.1.	Agreed to by all the Reliability Coordinators required to take the indicated action(s).	LOWER	RC			x							
IRO-014-1		R2.2.	Distributed to all Reliability Coordinators that are required to take the indicated action(s).	LOWER	RC			x							
IRO-014-1	R3.		A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator	MEDIUM	RC			x							
IRO-014-1		R3.1.	A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	MEDIUM	RC			x							
IRO-014-1		R3.2.	The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	LOWER	RC			x							
IRO-014-1	R4.		Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:	LOWER	RC			x							
IRO-014-1		R4.1.	Include version control number or date	LOWER	RC			x							

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IRO-014-1		R4.2.	Include a distribution list.	LOWER	RC			x							
IRO-014-1		R4.3.	Be reviewed, at least once every three years, and updated if needed.	LOWER	RC			x							
IRO-015-1	R1.		The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information	MEDIUM	RC										
IRO-015-1		R1.1.	The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may	MEDIUM	RC										
IRO-015-1	R2.		The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.	LOWER	RC										
IRO-015-1		R2.1.	The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	LOWER	RC										
IRO-015-1	R3.		The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.	MEDIUM	RC										
IRO-016-1	R1.		The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall	MEDIUM	RC										
IRO-016-1		R1.1.	If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability	MEDIUM	RC										
IRO-016-1		R1.2.	If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad	MEDIUM	RC										
IRO-016-1		R1.2.1.	If time permits, this re-evaluation shall be done before taking corrective actions.	MEDIUM	RC										
IRO-016-1		R1.2.2.	If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.	MEDIUM	RC										
IRO-016-1		R1.3.	If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	MEDIUM	RC										
IRO-016-1	R2.		The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the	LOWER	RC										
			MODELING, DATA AND ANALYSIS												
MOD-001-1a	R1.		Each Transmission Operator shall select one of the methodologies1 listed below for calculating Available Transfer Capability	Pending	TOP	x				A					X
MOD-001-1a	R2.		Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its	Pending	TSP	x				A					X

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MOD-001-1a		R2.1.	Hourly values for at least the next 48 hours.	Pending	TSP	x				A					X
MOD-001-1a		R2.2.	Daily values for at least the next 31 calendar days.	Pending	TSP	x				A					X
MOD-001-1a		R2.3.	Monthly values for at least the next 12 months (months 2-13).	Pending	TSP	x				A					X
MOD-001-1a	R3.		Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that	Pending	TSP	x				A					X
MOD-001-1a		R3.1.	Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the	Pending	TSP	x				A					X
MOD-001-1a		R3.2.	A description of the manner in which the Transmission Service Provider will account for counterflows including:	Pending	TSP	x				A					X
MOD-001-1a		R3.2.1.	How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or	Pending	TSP	x				A					X
MOD-001-1a		R3.2.2.	A rationale for that accounting specified in R3.2.	Pending	TSP	x				A					X
MOD-001-1a		R3.3.	The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in	Pending	TSP	x				A					X
MOD-001-1a		R3.4.	The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate	Pending	TSP	x				A					X
MOD-001-1a		R3.5.	A description of the allocation processes listed below that are applicable to the Transmission Service Provider: a) Processes used to allocate transfer or	Pending	TSP	x				A					X
MOD-001-1a		R3.6.	A description of how generation and transmission outages are considered in transfer or Flowgate capability calculations, including:	Pending	TSP	x				A					X
MOD-001-1a		R3.6.1.	The criteria used to determine when an outage that is in effect part of a day impacts a daily calculation.	Pending	TSP	x				A					X
MOD-001-1a		R3.6.2.	The criteria used to determine when an outage that is in effect part of a month impacts a monthly calculation.	Pending	TSP	x				A					X
MOD-001-1a		R3.6.3.	How outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer	Pending	TSP	x				A					X
MOD-001-1a	R4.		The Transmission Service Provider shall notify the following entities before implementing a new or revised ATCID:	Pending	TSP	x				A					X
MOD-001-1a		R4.1.	Each Planning Coordinator associated with the Transmission Service Provider's area.	Pending	TSP	x				A					X

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MOD-001-1a		R4.2.	Each Reliability Coordinator associated with the Transmission Service Provider's area.	Pending	TSP	x				A					X
MOD-001-1a		R4.3.	Each Transmission Operator associated with the Transmission Service Provider's area.	Pending	TSP	x				A					X
MOD-001-1a		R4.4.	Each Planning Coordinator adjacent to the Transmission Service Provider's area.	Pending	TSP	x				A					X
MOD-001-1a		R4.5.	Each Reliability Coordinator adjacent to the Transmission Service Provider's area	Pending	TSP	x				A					X
MOD-001-1a		R4.6.	Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.	Pending	TSP	x				A					X
MOD-001-1a	R5.		The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4.	Pending	TSP	x				A					X
MOD-001-1a	R6.		When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more	Pending	TOP	x				A					X
MOD-001-1a	R7.		When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for	Pending	TSP	x				A					X
MOD-001-1a	R8.		Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values	Pending	TSP	x				A					X
MOD-001-1a		R8.1.	Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not	Pending	TSP	x				A					X
MOD-001-1a		R8.2.	Daily values, once per day	Pending	TSP	x				A					X
MOD-001-1a		R8.3.	Monthly values, once per week.	Pending	TSP	x				A					X
MOD-001-1a	R9.		Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission	Pending	TSP	x				A					X
MOD-001-1a		R9.1.	Transmission Service.	Pending	TSP	x				A					X
MOD-001-1a		R9.1.1.	If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data	Pending	TSP	x				A					X
MOD-001-1a		R9.1.2.	If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that	Pending	TSP	x				A					X
MOD-001-1a		R9.1.3.	If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that	Pending	TSP	x				A					X

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MOD-001-1a		R9.2.	This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless	Pending	TSP	x				A					X
MOD-004-1	R1.		The Transmission Service Provider that maintains CBM shall prepare and keep current a “Capacity Benefit Margin Implementation Document” (CBMID) that	Pending	TSP	x				A					X
MOD-004-1		R1.1.	The process through which a Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the	Pending	TSP	x				A					X
MOD-004-1		R1.2.	The procedure and assumptions for establishing CBM for each Available Transfer Capability (ATC) Path or Flowgate.	Pending	TSP	x				A					X
MOD-004-1		R1.3.	The procedure for a Load-Serving Entity or Balancing Authority to use Transmission capacity set aside as CBM, including the manner in which the	Pending	TSP	x				A					X
MOD-004-1	R2.		The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service	Pending	TSP	x				A					X
MOD-004-1	R3.		Each Load-Serving Entity determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine	Pending	LSE	x				A					X
MOD-004-1		R3.1.	Using one or more of the following to determine the GCIR: a) Loss of Load Expectation (LOLE) studies	Pending	LSE	x				A					X
MOD-004-1		R3.2.	Identifying expected import path(s) or source region(s).	Pending	LSE	x				A					X
MOD-004-1	R4.		Each Resource Planner determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine	Pending	RP	x				A					X
MOD-004-1		R4.1.	Using one or more of the following to determine the GCIR: a) Loss of Load Expectation (LOLE) studies	Pending	RP	x				A					X
MOD-004-1		R4.2.	Identifying expected import path(s) or source region(s).	Pending	RP	x				A					X
MOD-004-1	R5.		At least every 13 months, the Transmission Service Provider that maintains CBM shall establish a CBM value for each ATC Path or Flowgate to	Pending	TSP	x				A					X
MOD-004-1		R5.1.	Reflect consideration of each of the following if available: a) Any studies (as described in R3.1) performed by Load-Serving Entities for	Pending	TSP	x				A					X
MOD-004-1		R5.2.	Be allocated as follows: a) For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or	Pending	TSP	x				A					X
MOD-004-1	R6.		At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used in planning during	Pending	TP	x				A					X
MOD-004-1		R6.1.	Reflect consideration of each of the following if available: a) Any studies (as described in R3.1) performed by Load-Serving Entities for	Pending	TP	x				A					X

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MOD-004-1		R6.2.	Be allocated as follows: a) For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or	Pending	TP	x				A					X
MOD-004-1	R7.		Less than 31 calendar days after the establishment of CBM, the Transmission Service Provider that maintains CBM shall notify all the Load-Serving Entities	Pending	TSP	x				A					X
MOD-004-1	R8.		Less than 31 calendar days after the establishment of CBM, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that	Pending	TP	x				A					X
MOD-004-1	R9.		The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide (subject to confidentiality and security	Pending	TSP, TP	x				A					X
MOD-004-1		R9.1.	Each of its associated Transmission Operators within 30 calendar days of their making a request for the data.	Pending	TSP, TP	x				A					X
MOD-004-1		R9.2.	To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, Resource Planner, or Planning Coordinator within 30 calendar days of	Pending	TSP, TP	x				A					X
MOD-004-1	R10.		The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared	Pending	BA, LSE	x				A					X
MOD-004-1	R11.		When reviewing an Arranged Interchange using CBM, all Balancing Authorities and Transmission Service Providers shall waive, within the bounds of reliable	Pending	BA, TSP	x				A					X
MOD-004-1	R12.		The Transmission Service Provider that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is	Pending	TSP	x				A					X
MOD-004-1		R12.1.	The CBM is available	Pending	TSP	x				A					X
MOD-004-1		R12.2.	The EEA 2 is declared within the Balancing Authority Area of the “energy deficient entity,” and	Pending	TSP	x				A					X
MOD-004-1		R12.3.	The Load of the “energy deficient entity” is located within the Transmission Service Provider’s area.	Pending	TSP	x				A					X
MOD-008-1	R1.		Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following	*Pending*	TOP	x				A					X
MOD-008-1		R1.1.	Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM,	*Pending*	TOP	x				A					X
MOD-008-1		R1.2.	The description of the method used to allocate TRM across ATC Paths or Flowgates.	*Pending*	TOP	x				A					X
MOD-008-1		R1.3.	The identification of the TRM calculation used for the following time periods:	*Pending*	TOP	x				A					X
MOD-008-1		R1.3.1.	Same day and real-time.	*Pending*	TOP	x				A					X

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MOD-008-1		R1.3.2.	Day-ahead and pre-schedule.	*Pending*	TOP	x				A					X
MOD-008-1		R1.3.3.	Beyond day-ahead and pre-schedule, up to thirteen months ahead.	*Pending*	TOP	x				A					X
MOD-008-1	R2.		Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of	*Pending*	TOP	x				A					X
MOD-008-1	R3.		Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by	*Pending*	TOP	x				A					X
MOD-008-1	R4.		Each Transmission Operator that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months.	*Pending*	TOP	x				A					X
MOD-008-1	R5.		The Transmission Operator that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s)	*Pending*	TOP	x				A					X
MOD-010-0	R1.		The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures	MEDIUM	GO, RP, TO, TP										
MOD-010-0	R2.		The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures	MEDIUM	GO, RP, TO, TP						A				
MOD-012-0	R1.		The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures	MEDIUM	GO, RP, TO, TP										
MOD-012-0	R2.		The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures	MEDIUM	GO, RP, TO, TP						A				
MOD-016-1.1	R1.		The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a)	LOWER	PA, PC, RRO										
MOD-016-1.1		R1.1.	The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010,	LOWER	PA, PC, RRO										
MOD-016-1.1	R2.		The Regional Reliability Organization shall distribute its documentation required in Requirement 1 and any changes to that documentation, to all	LOWER	RRO										
MOD-016-1.1		R2.1.	The Regional Reliability Organization shall make this distribution within 30 calendar days of approval.	LOWER	RRO										
MOD-016-1.1	R3.		The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its	LOWER	PA, PC										
MOD-016-1.1		R3.1.	The Planning Authority shall make this distribution within 30 calendar days of approval.	LOWER	PA, PC										
MOD-017-0.1	R1.		The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional,	MEDIUM	LSE, PA, PC, RP										

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MOD-017-0.1		R1.1.	Integrated hourly demands in megawatts (MW) for the prior year.	MEDIUM	LSE, PA, PC, RP										
MOD-017-0.1		R1.2.	Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.	MEDIUM	LSE, PA, PC, RP										
MOD-017-0.1		R1.3.	Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.	MEDIUM	LSE, PA, PC, RP										
MOD-017-0.1		R1.4.	Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the	MEDIUM	LSE, PA, PC, RP										
MOD-018-0	R1.		The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast demand data (reported on either	MEDIUM	LSE, PA, PC, RP, TP										
MOD-018-0		R1.1.	Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and	MEDIUM	LSE, PA, PC, RP, TP										
MOD-018-0		R1.2.	Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load.	LOWER	LSE, PA, PC, RP, TP										
MOD-018-0		R1.3.	Items (MOD-018-0_R 1.1) and (MOD-018-0_R 1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-1_R 1.	LOWER	LSE, PA, PC, RP, TP										
MOD-018-0	R2.		The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each report data associated with Reliability Standard MOD-	LOWER	LSE, PA, PC, RP, TP										
MOD-019-0.1	R1.		The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible	MEDIUM	LSE, PA, PC, RP, TP										
MOD-020-0	R1.		The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control	LOWER	LSE, RP, TP										
MOD-021-1	R1.		The Load-Serving Entity, Transmission Planner and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of	LOWER	LSE, RP, TP										
MOD-021-1	R2.		The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are	LOWER	LSE, RP, TP										
MOD-021-1	R3.		The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on	LOWER	LSE, RP, TP										
MOD-028-1	R1.		Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following	Pending	TSP		x								
MOD-028-1		R1.1.	Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission	Pending	TSP		x								
MOD-028-1		R1.2.	A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.	Pending	TSP		x								

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MOD-028-1		R1.3.	Any contractual obligations for allocation of TTC.	Pending	TSP		x								
MOD-028-1		R1.4.	A description of the manner in which Contingencies are identified for use in the TTC process.	Pending	TSP		x								
MOD-028-1		R1.5.	The following information on how source and sink for transmission service is accounted for in ATC calculations including:	Pending	TSP		x								
MOD-028-1		R1.5.1.	Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt	Pending	TSP		x								
MOD-028-1		R1.5.2.	Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission	Pending	TSP		x								
MOD-028-1		R1.5.3.	The source/sink or POR/POD identification and mapping to the model	Pending	TSP		x								
MOD-028-1		R1.5.4.	If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how	Pending	TSP		x								
MOD-028-1	R2.		When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following:	Pending	TOP		x								
MOD-028-1		R2.1.	Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or	Pending	TOP		x								
MOD-028-1		R2.2.	Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.	Pending	TOP		x								
MOD-028-1		R2.3.	Facility Ratings specified by the Generator Owners and Transmission Owners.	Pending	TOP		x								
MOD-028-1	R3.		When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The	Pending	TOP		x								
MOD-028-1		R3.1.	For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):	Pending	TOP		x								
MOD-028-1		R3.1.1.	Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.	Pending	TOP		x								
MOD-028-1		R3.1.2.	Load forecast for the applicable period being calculated.	Pending	TOP		x								
MOD-028-1		R3.1.3.	Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the	Pending	TOP		x								
MOD-028-1		R3.2.	For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in	Pending	TOP		x								

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MOD-028-1		R3.2.1.	Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.	Pending	TOP		x								
MOD-028-1		R3.2.2.	Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months	Pending	TOP		x								
MOD-028-1		R3.2.3.	Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the	Pending	TOP		x								
MOD-028-1	R4.		When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions:	Pending	TOP		x								
MOD-028-1		R4.1.	Use all Contingencies meeting the criteria described in the ATCID.	Pending	TOP		x								
MOD-028-1		R4.2.	Respect any contractual allocations of TTC.	Pending	TOP		x								
MOD-028-1		R4.3.	Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate	Pending	TOP		x								
MOD-028-1	R5.		Each Transmission Operator shall establish TTC for each ATC Path as defined below:	Pending	TOP		x								
MOD-028-1		R5.1.	At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.	Pending	TOP		x								
MOD-028-1		R5.2.	At least once per calendar month for TTCs used in monthly ATC calculations.	Pending	TOP		x								
MOD-028-1		R5.3.	Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or	Pending	TOP		x								
MOD-028-1	R6.		Each Transmission Operator shall establish TTC for each ATC Path using the following process:	Pending	TOP		x								
MOD-028-1		R6.1.	Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing	Pending	TOP		x								
MOD-028-1		R6.2.	If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the	Pending	TOP		x								
MOD-028-1		R6.3.	Use (as the TTC) the lesser of: - The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in	Pending	TOP		x								
MOD-028-1		R6.4.	For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed	Pending	TOP		x								
MOD-028-1	R7.		The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more	Pending	TOP		x								

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MOD-028-1		R7.1.	One calendar day after its determination for TTCs used in hourly and daily ATC calculations.	Pending	TOP		x								
MOD-028-1		R7.2.	Seven calendar days after its determination for TTCs used in monthly ATC calculations.	Pending	TOP		x								
MOD-028-1	R8.		When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETCF) for all time periods for an ATC Path the Transmission	Pending	TSP		x								
MOD-028-1	R9.		When calculating ETC for non-firm commitments (ETCNF) for all time periods for an ATC Path the Transmission Service Provider shall use	Pending	TSP		x								
MOD-028-1	R10.		When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm:	Pending	TSP		x								
MOD-028-1	R11.		When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm:	Pending	TSP		x								
MOD-029-1a	R1.		When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements:	Pending	TOP		x								
MOD-029-1a		R1.1.	The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:	Pending	TOP		x								
MOD-029-1a		R1.1.1.	Includes at least:	Pending	TOP		x								
MOD-029-1a		R1.1.1.1.	The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.	Pending	TOP		x								
MOD-029-1a		R1.1.1.2.	All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)	Pending	TOP		x								
MOD-029-1a		R1.1.1.3.	Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.	Pending	TOP		x								
MOD-029-1a		R1.1.2.	Models all system Elements as in-service for the assumed initial conditions.	Pending	TOP		x								
MOD-029-1a		R1.1.3.	Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the	Pending	TOP		x								
MOD-029-1a		R1.1.4.	Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation	Pending	TOP		x								
MOD-029-1a		R1.1.5.	Uses Load forecast by Balancing Authority.	Pending	TOP		x								
MOD-029-1a		R1.1.6.	Uses Transmission Facility additions and retirements.	Pending	TOP		x								

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MOD-029-1a		R1.1.7.	Uses Generation Facility additions and retirements.	Pending	TOP		x								
MOD-029-1a		R1.1.8.	Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time	Pending	TOP		x								
MOD-029-1a		R1.1.9.	Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.	Pending	TOP		x								
MOD-029-1a		R1.1.10.	Includes any other modeling requirements or criteria specified in the ATCID.	Pending	TOP		x								
MOD-029-1a		R1.2.	Uses Facility Ratings as provided by the Transmission Owner and Generator Owner	Pending	TOP		x								
MOD-029-1a	R2.		The Transmission Operator shall use the following process to determine TTC:	Pending	TOP		x								
MOD-029-1a		R2.1.	Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine	Pending	TOP		x								
MOD-029-1a		R2.1.1.	When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.	Pending	TOP		x								
MOD-029-1a		R2.1.2.	When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its	Pending	TOP		x								
MOD-029-1a		R2.1.3.	Uncontrolled separation shall not occur.	Pending	TOP		x								
MOD-029-1a		R2.2.	Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line),	Pending	TOP		x								
MOD-029-1a		R2.3.	For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the	Pending	TOP		x								
MOD-029-1a		R2.4.	For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths	Pending	TOP		x								
MOD-029-1a		R2.5.	The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do	Pending	TOP		x								
MOD-029-1a		R2.6.	Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in	Pending	TOP		x								
MOD-029-1a		R2.7.	For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no	Pending	TOP		x								
MOD-029-1a		R2.8.	Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining	Pending	TOP		x								

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MOD-029-1a	R3.		Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path.	Pending	TOP		x								
MOD-029-1a	R4.		Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service	Pending	TOP		x								
MOD-029-1a	R5.		When calculating ETC for firm Existing Transmission Commitments (ETCF) for a specified period for an ATC Path, the Transmission Service Provider shall use	Pending	TSP		x								
MOD-029-1a	R6.		When calculating ETC for non-firm Existing Transmission Commitments (ETCNF) for all time horizons for an ATC Path the Transmission Service Provider	Pending	TSP		x								
MOD-029-1a	R7.		When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm:	Pending	TSP		x								
MOD-029-1a	R8.		When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm:	Pending	TSP		x								
MOD-030-2	R1.		The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID):	Pending	TSP		x								
MOD-030-2		R1.1.	The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate	Pending	TSP		x								
MOD-030-2		R1.2.	The following information on how source and sink for transmission service is accounted for in AFC calculations including:	Pending	TSP		x								
MOD-030-2		R1.2.1.	Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.	Pending	TSP		x								
MOD-030-2		R1.2.2.	Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.	Pending	TSP		x								
MOD-030-2		R1.2.3.	The source/sink or POR/POD identification and mapping to the model.	Pending	TSP		x								
MOD-030-2		R1.2.4.	If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators	Pending	TSP		x								
MOD-030-2	R2.		The Transmission Operator shall perform the following: [Violation Risk Factor:	Pending	TOP		x								
MOD-030-2		R2.1.	Include Flowgates used in the AFC process based, at a minimum, on the following criteria:	Pending	TOP		x								
MOD-030-2		R2.1.1.	Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a	Pending	TOP		x								
MOD-030-2		R2.1.1.1.	Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of	Pending	TOP		x								

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MOD-030-2		R2.1.1.2.	Only the most limiting element in a series configuration needs to be included as a Flowgate.	Pending	TOP		x								
MOD-030-2		R2.1.1.3.	If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new	Pending	TOP		x								
MOD-030-2		R2.1.2.	Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path	Pending	TOP		x								
MOD-030-2		R2.1.2.1.	Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of	Pending	TOP		x								
MOD-030-2		R2.1.2.2.	Only the most limiting element in a series configuration needs to be included as a Flowgate.	Pending	TOP		x								
MOD-030-2		R2.1.2.3.	If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new	Pending	TOP		x								
MOD-030-2		R2.1.3.	Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an	Pending	TOP		x								
MOD-030-2		R2.1.4.	Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission	Pending	TOP		x								
MOD-030-2		R2.1.4.1.	The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and - Any	Pending	TOP		x								
MOD-030-2		R2.1.4.2.	The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.	Pending	TOP		x								
MOD-030-2		R2.2.	At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.	Pending	TOP		x								
MOD-030-2		R2.3.	At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty	Pending	TOP		x								
MOD-030-2		R2.4.	Establish the TFC of each of the defined Flowgates as equal to: - For thermal limits, the System Operating Limit (SOL) of the Flowgate.	Pending	TOP		x								
MOD-030-2		R2.5.	At a minimum, establish the TFC once per calendar year.	Pending	TOP		x								
MOD-030-2		R2.5.1.	If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated	Pending	TOP		x								
MOD-030-2		R2.6.	Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	Pending	TOP		x								
MOD-030-2	R3.		The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability	Pending	TOP		x								

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MOD-030-2		R3.1.	Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within	Pending	TOP		x								
MOD-030-2		R3.2.	Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.	Pending	TOP		x								
MOD-030-2		R3.3.	Updated at least once per month for AFC calculations for months two through 13.	Pending	TOP		x								
MOD-030-2		R3.4.	Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and	Pending	TOP		x								
MOD-030-2		R3.5.	Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.	Pending	TOP		x								
MOD-030-2	R4.		When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows:	Pending	TSP		x								
MOD-030-2	R5.		When calculating AFCs, the Transmission Service Provider shall:	Pending	TSP		x								
MOD-030-2		R5.1.	Use the models provided by the Transmission Operator.	Pending	TSP		x								
MOD-030-2		R5.2.	Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as	Pending	TSP		x								
MOD-030-2		R5.3.	For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.	Pending	TSP		x								
MOD-030-2	R6.		When calculating the impact of ETC for firm commitments (ETCFi) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following:	Pending	TSP		x								
MOD-030-2		R6.1.	The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the	Pending	TSP		x								
MOD-030-2		R6.1.1.	Load forecast for the time period being calculated, including Native Load and Network Service load	Pending	TSP		x								
MOD-030-2		R6.1.2.	Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as	Pending	TSP		x								
MOD-030-2		R6.2.	The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and	Pending	TSP		x								
MOD-030-2		R6.2.1.	Load forecast for the time period being calculated, including Native Load and Network Service load	Pending	TSP		x								
MOD-030-2		R6.2.2.	Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as	Pending	TSP		x								

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MOD-030-2		R6.3.	The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts,	Pending	TSP		x								
MOD-030-2		R6.4.	The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from	Pending	TSP		x								
MOD-030-2		R6.5.	The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.	Pending	TSP		x								
MOD-030-2		R6.6.	The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the	Pending	TSP		x								
MOD-030-2		R6.7.	The impact of other firm services determined by the Transmission Service Provider.	Pending	TSP		x								
MOD-030-2	R7.		When calculating the impact of ETC for non-firm commitments (ETCNFi) for all time periods for a Flowgate the Transmission Service Provider shall	Pending	TSP		x								
MOD-030-2		R7.1.	The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.	Pending	TSP		x								
MOD-030-2		R7.2.	The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts	Pending	TSP		x								
MOD-030-2		R7.3.	The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.	Pending	TSP		x								
MOD-030-2		R7.4.	The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater	Pending	TSP		x								
MOD-030-2		R7.5.	The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service	Pending	TSP		x								
MOD-030-2		R7.6.	The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal	Pending	TSP		x								
MOD-030-2		R7.7.	The impact of other non-firm services determined by the Transmission Service Provider.	Pending	TSP		x								
MOD-030-2	R8.		When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to	Pending	TSP		x								
MOD-030-2	R9.		When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to	Pending	TSP		x								
MOD-030-2	R10.		Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following	Pending	TSP		x								
MOD-030-2		R10.1.	For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during	Pending	TSP		x								

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MOD-030-2		R10.2.	For daily AFC, once per day.	Pending	TSP		x								
MOD-030-2		R10.3.	For monthly AFC, once per week	Pending	TSP		x								
MOD-030-2	R11.		When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm:	Pending	TSP		x								
			NUCLEAR												
NUC-001-2	R1.		The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt	LOWER	Nuclear GO and Nuclear GOP			x							
NUC-001-2	R2.		The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements[FN1] that include mutually	MEDIUM	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2	R3.		Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning	MEDIUM	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,			x							
NUC-001-2	R4.		Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall:	HIGH	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	x									
NUC-001-2		R4.1.	Incorporate the NPIRs into their operating analyses of the electric system.	Part of Main Requirement	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	x									
NUC-001-2		R4.2.	Operate the electric system to meet the NPIRs.	Part of Main Requirement	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	x									
NUC-001-2		R4.3.	Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.	Part of Main Requirement	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,	x									
NUC-001-2	R5.		The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard.	HIGH	Nuclear GO and Nuclear GOP	x									
NUC-001-2	R6.		Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall	MEDIUM	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2	R7.		Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission	HIGH	Nuclear GO and Nuclear GOP			x							
NUC-001-2	R8.		Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator	HIGH	Transmission Entities that can include: BA, DP, GO, GOP, LSE, PA,			x							
NUC-001-2	R9.		The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the	MEDIUM	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.1.	Administrative elements:	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							

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NUC-001-2		R9.1.1.	Definitions of key terms used in the agreement.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.1.2.	Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.1.3.	A requirement to review the agreement(s) at least every three years.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.1.4.	A dispute resolution mechanism.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.2.	Technical requirements and analysis:	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.2.1.	Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.2.2.	Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.2.3.	Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.	Operations and maintenance coordination:	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.1.	Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.2.	Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.3.	Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.4.	Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.5.	Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,		x								
NUC-001-2		R9.3.6.	Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.3.7.	Coordination of the NPIRs with transmission system Special Protection Systems and underfrequency and undervoltage load shedding programs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.4.	Communications and training:	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,		x								

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NUC-001-2		R9.4.1.	Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,		x								
NUC-001-2		R9.4.2.	Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event,	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,			x							
NUC-001-2		R9.4.3.	Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,		x								
NUC-001-2		R9.4.4.	Provisions for supplying information necessary to report to government agencies, as related to NPIRs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,		x								
NUC-001-2		R9.4.5.	Provisions for personnel training, as related to NPIRs.	Part of Main Requirement	Nuclear GOP and Transmission Entities that can include: BA, DP,		x								
			PERSONNEL PERFORMANCE, TRAINING AND QUALIFICATIONS												
PER-001-0.1	R1.		Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement	HIGH	BA, TOP		x								
PER-002-0	R1.		Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.	HIGH	BA, TOP		x			A					X
PER-002-0	R2.		Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:	HIGH	BA, TOP	x				A					X
PER-002-0		R2.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected	HIGH	BA, TOP	x				A					X
PER-002-0		R2.2.	Positions directly responsible for complying with NERC standards.	HIGH	BA, TOP	x				A					X
PER-002-0	R3.		For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following	HIGH	BA, TOP	x				A					X
PER-002-0		R3.1.	A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures,	MEDIUM	BA, TOP	x				A					X
PER-002-0		R3.2.	The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan	MEDIUM	BA, TOP	x				A					X
PER-002-0		R3.3.	The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their	LOWER	BA, TOP	x				A					X
PER-002-0		R3.4.	Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.	LOWER	BA, TOP	x				A					X
PER-002-0 (retired 4/1/2011)	R4.		For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per	HIGH	BA, TOP					A					X

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PER-003-0	R1.		Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with	HIGH	BA, RC, TOP							ER			
PER-003-0		R1.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected	HIGH	BA, RC, TOP							ER			
PER-003-0		R1.2.	Positions directly responsible for complying with NERC standards.	HIGH	BA, RC, TOP							ER			
PER-003-1 (effective 10/1/2012)	R1.		Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System	HIGH	RC							ER			
PER-003-1 (effective 10/1/2012)	R2.		Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System	HIGH	TOP							ER			
PER-003-1 (effective 10/1/2012)	R3.		Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have	HIGH	BA							ER			
PER-004-1 (retired 4/1/2011)	R1.		Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.	HIGH	RC										X
PER-004-1 (retired 4/1/2011)	R2.		All Reliability Coordinator operating personnel shall each complete a minimum of five days per year of training and drills using realistic simulations of	HIGH	RC										
PER-004-1	R3.		Reliability Coordinator operating personnel shall have a comprehensive understanding of the Reliability Coordinator Area and interactions with	HIGH	RC										
PER-004-1	R4.		Reliability Coordinator operating personnel shall have an extensive understanding of the Balancing Authorities, Transmission Operators,	HIGH	RC										
PER-004-1 (retired 4/1/2011)	R5.		Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall	HIGH	RC										
PER-004-2	R1.		Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days	Pending	RC										
PER-004-2	R2.		Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall	Pending	RC										
PER-005-1 (effective 4/1/2013)	R1.		Each Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program	MEDIUM	BA, RC, TOP										
PER-005-1 (effective 4/1/2013)		R1.1.	Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks	MEDIUM	BA, RC, TOP										
PER-005-1 (effective 4/1/2013)		R1.1.1.	Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES company-specific reliability-related tasks	MEDIUM	BA, RC, TOP										
PER-005-1 (effective 4/1/2013)		R1.2.	Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based	MEDIUM	BA, RC, TOP										

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PER-005-1 (effective 4/1/2013)		R1.3.	Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2.	MEDIUM	BA, RC, TOP										
PER-005-1 (effective 4/1/2013)		R1.4.	Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to	MEDIUM	BA, RC, TOP										
PER-005-1 (effective 4/1/2013)	R2.		Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform each assigned	HIGH	BA, RC, TOP										
PER-005-1 (effective 4/1/2013)		R2.1.	Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and	HIGH	BA, RC, TOP										
PER-005-1 (effective 4/1/2011)	R3.		At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at	MEDIUM	BA, RC, TOP			x							
PER-005-1 (effective 4/1/2014)		R3.1	Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or	MEDIUM	BA, RC, TOP										
			PROTECTION AND CONTROL												
PRC-001-1	R1.		Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	HIGH	BA, GOP, TOP	x				A					X
PRC-001-1	R2.		Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	HIGH	GOP, TOP		x			A					X
PRC-001-1		R2.1.	If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority.	HIGH	GOP	x				A					X
PRC-001-1		R2.2.	If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected	HIGH	TOP	x				A					X
PRC-001-1	R3.		A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.	No VRF Assigned	GOP, TOP		x			A					X
PRC-001-1		R3.1.	Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host	HIGH	GOP	x				A					X
PRC-001-1		R3.2.	Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and	HIGH	TOP	x				A					X
PRC-001-1	R4.		Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators,	HIGH	TOP		x			A					X
PRC-001-1	R5.		A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require	HIGH	GOP, TOP		x			A					X
PRC-001-1		R5.1.	Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in	HIGH	GOP		x			A					X

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PRC-001-1		R5.2.	Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating	HIGH	TOP		x			A					X
PRC-001-1	R6.		Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected	HIGH	BA, TOP		x			A					X
PRC-004-1	R1.		The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.	HIGH	DP, TO		x			A					X
PRC-004-1	R2.		The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.	HIGH	GO		x								X
PRC-004-1	R3.		The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations	LOWER	DP, GO, TO		x								
PRC-004-2a (effective 4/1/2012)	R1.		The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan	HIGH	DP, TO										
PRC-004-2a (effective 4/1/2012)	R2.		The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's	HIGH	GO										
PRC-004-2a (effective 4/1/2012)	R3.		The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective	LOWER	DP, GO, TO										
PRC-005-1	R1.		Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a	HIGH	DP, GO, TO		x			A					X
PRC-005-1		R1.1.	Maintenance and testing intervals and their basis.	HIGH	DP, GO, TO		x			A					X
PRC-005-1		R1.2.	Summary of maintenance and testing procedures.	HIGH	DP, GO, TO		x			A					X
PRC-005-1	R2.		Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a	LOWER	DP, GO, TO	x				A					X

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PRC-005-1		R2.1.	Evidence Protection System devices were maintained and tested within the defined intervals.	HIGH	DP, GO, TO	x				A					X
PRC-005-1		R2.2.	Date each Protection System device was last tested/maintained.	HIGH	DP, GO, TO	x				A					X
PRC-007-0	R1.		The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall ensure that	MEDIUM	DP, TO										
PRC-007-0	R2.		The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to	LOWER	DP, LSE, TO, TOP						A				
PRC-007-0	R3.		The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its	LOWER	DP, TO										
PRC-008-0	R1.		The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.	MEDIUM	DP, TO			x		A					X
PRC-008-0	R2.		The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement	MEDIUM	DP, TO			x		A					X
PRC-009-0	R1.		The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by	MEDIUM	DP, LSE, TO, TOP										
PRC-009-0		R1.1.	A description of the event including initiating conditions.	MEDIUM	DP, LSE, TO, TOP										
PRC-009-0		R1.2.	A review of the UFLS set points and tripping times.	MEDIUM	DP, LSE, TO, TOP										
PRC-009-0		R1.3.	A simulation of the event.	MEDIUM	DP, LSE, TO, TOP										
PRC-009-0		R1.4.	A summary of the findings.	MEDIUM	DP, LSE, TO, TOP										
PRC-009-0	R2.		The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by	LOWER	DP, LSE, TO, TOP										
PRC-010-0	R1.		The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall	MEDIUM	DP, LSE, TO, TOP										

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PRC-010-0		R1.1.	This assessment shall include, but is not limited to:	MEDIUM	DP, LSE, TO, TOP										
PRC-010-0		R1.1.1.	Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.	MEDIUM	DP, LSE, TO, TOP										
PRC-010-0		R1.1.2.	Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-	MEDIUM	DP, LSE, TO, TOP										
PRC-010-0		R1.1.3.	A review of the voltage set points and timing.	MEDIUM	DP, LSE, TO, TOP										
PRC-010-0	R2.		The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide	LOWER	DP, LSE, TO, TOP										
PRC-011-0	R1.		The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in	MEDIUM	DP, TO			x							X
PRC-011-0		R1.1.	The UVLS system identification which shall include but is not limited to:	MEDIUM	DP, TO			x							X
PRC-011-0		R1.1.1.	Relays.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.1.2.	Instrument transformers.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.1.3.	Communications systems, where appropriate.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.1.4.	Batteries.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.2.	Documentation of maintenance and testing intervals and their basis.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.3.	Summary of testing procedure.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.4.	Schedule for system testing.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.5.	Schedule for system maintenance.	MEDIUM	DP, TO			x							X
PRC-011-0		R1.6.	Date last tested/maintained.	MEDIUM	DP, TO			x							X

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PRC-011-0	R2.		The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).	LOWER	DP, TO			x		A					
PRC-015-0	R1.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed	MEDIUM	DP, GO, TO										
PRC-015-0	R2.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified	MEDIUM	DP, GO, TO										
PRC-015-0	R3.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the	LOWER	DP, GO, TO										
PRC-016-0.1	R1.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all	MEDIUM	DP, GO, TO										
PRC-016-0.1	R2.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.	MEDIUM	DP, GO, TO										
PRC-016-0.1	R3.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation	LOWER	DP, GO, TO							ER			
PRC-017-0	R1.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.1.	SPS identification shall include but is not limited to:	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.1.1.	Relays.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.1.2.	Instrument transformers.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.1.3.	Communications systems, where appropriate.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.1.4.	Batteries.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.2.	Documentation of maintenance and testing intervals and their basis.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.3.	Summary of testing procedure.	HIGH	DP, GO, TO			x							X

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PRC-017-0		R1.4.	Schedule for system testing.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.5.	Schedule for system maintenance.	HIGH	DP, GO, TO			x							X
PRC-017-0		R1.6.	Date last tested/maintained.	MEDIUM	DP, GO, TO			x							X
PRC-017-0	R2.		The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its	LOWER	DP, GO, TO			x		A					X
PRC-018-1	R1.		Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-	LOWER	GO, TO										
PRC-018-1		R1.1.	Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)	LOWER	GO, TO										
PRC-018-1		R1.2.	Recorded data from each Disturbance shall be retrievable for ten calendar days..	LOWER	GO, TO										
PRC-018-1	R2.		The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements	LOWER	GO, TO										
PRC-018-1	R3.		The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs	LOWER	GO, TO										
PRC-018-1		R3.1.	Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).	LOWER	GO, TO										
PRC-018-1		R3.2.	Make and model of equipment.	LOWER	GO, TO										
PRC-018-1		R3.3.	Installation location.	LOWER	GO, TO										
PRC-018-1		R3.4.	Operational status.	LOWER	GO, TO										
PRC-018-1		R3.5.	Date last tested.	LOWER	GO, TO										
PRC-018-1		R3.6.	Monitored elements, such as transmission circuit, bus section, etc.	LOWER	GO, TO										
PRC-018-1		R3.7.	Monitored devices, such as circuit breaker, disconnect status, alarms, etc.	LOWER	GO, TO										
PRC-018-1		R3.8.	Monitored electrical quantities, such as voltage, current, etc.	LOWER	GO, TO										

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PRC-018-1	R4.		The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability	LOWER	GO, TO										
PRC-018-1	R5.		The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events	LOWER	GO, TO										
PRC-018-1	R6.		Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and	LOWER	GO, TO										
PRC-018-1		R6.1.	Maintenance and testing intervals and their basis.	LOWER	GO, TO										
PRC-018-1		R6.2.	Summary of maintenance and testing procedures.	LOWER	GO, TO										
PRC-021-1	R1.		Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES	LOWER	DP, TO						A				
PRC-021-1		R1.1.	Size and location of customer load, or percent of connected load, to be interrupted.	LOWER	DP, TO						A				
PRC-021-1		R1.2.	Corresponding voltage set points and overall scheme clearing times.	MEDIUM	DP, TO						A				
PRC-021-1		R1.3.	Time delay from initiation to trip signal.	LOWER	DP, TO						A				
PRC-021-1		R1.4.	Breaker operating times.	LOWER	DP, TO						A				
PRC-021-1		R1.5.	Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration	LOWER	DP, TO						A				
PRC-021-1	R2.		Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability	LOWER	DP, TO										
PRC-022-1	R1.		Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage	MEDIUM	DP, LSE, TOP										
PRC-022-1		R1.1.	A description of the event including initiating conditions.	LOWER	DP, LSE, TOP										
PRC-022-1		R1.2.	A review of the UVLS set points and tripping times.	MEDIUM	DP, LSE, TOP										
PRC-022-1		R1.3.	A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient	LOWER	DP, LSE, TOP										
PRC-022-1		R1.4.	A summary of the findings.	LOWER	DP, LSE, TOP										

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PRC-022-1		R1.5.	For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.	MEDIUM	DP, LSE, TOP										
PRC-022-1	R2.		Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of	LOWER	DP, LSE, TOP										
PRC-023-1	R1.		Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees:	HIGH	TO, GO, DP		x			A					X
PRC-023-1		R1.1.	Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.2.	Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating of a circuit (expressed in	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.3.	Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.3.1.	An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.3.2.	An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.4.	Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line,	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.5.	Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.6.	Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.7.	Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.8.	Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.9.	Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of	Part of Main Requirement	TO, GO, DP		x			A					X

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PRC-023-1		R1.10.	Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.11.	For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.12.	When the desired transmission line capability is limited by the requirement to adequately protect the transmission line,	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.12.1.	Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.12.2.	Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.12.3.	Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1		R1.13.	Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such	Part of Main Requirement	TO, GO, DP		x			A					X
PRC-023-1	R2.		The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8,	MEDIUM	TO, GO, DP			x							
PRC-023-1	R3.		The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low	MEDIUM	PA, PC		x			A					
PRC-023-1		R3.1.	The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.	Part of Main Requirement	PA, PC		x			A					
PRC-023-1		R3.1.1.	This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.	Part of Main Requirement	PA, PC		x			A					
PRC-023-1		R3.2.	The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.	Part of Main Requirement	PA, PC		x			A					
PRC-023-1		R3.3.	The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution	Part of Main Requirement	PA, PC		x			A					
			TRANSMISSION OPERATIONS												
TOP-001-1	R1.		Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	HIGH	TOP		x								
TOP-001-1	R2.		Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy	HIGH	TOP		x								

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TOP-001-1	R3.		Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission	HIGH	BA, GOP, TOP		x								
TOP-001-1	R4.		Each Distribution Provider and Load-Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including	HIGH	DP, LSE		x								
TOP-001-1	R5.		Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real-time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	HIGH	TOP		x								
TOP-001-1	R6.		Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested,	HIGH	BA, GOP, TOP		x								
TOP-001-1	R7.		Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would	HIGH	GOP, TOP		x								
TOP-001-1		R7.1.	For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the	HIGH	GOP, TOP		x								
TOP-001-1		R7.2.	For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator	HIGH	TOP		x								
TOP-001-1		R7.3.	When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer	HIGH	GOP, TOP		x								
TOP-001-1	R8.		During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to	HIGH	BA, RC, TOP		x								
TOP-002-2a	R1.		Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	MEDIUM	BA, TOP		x								
TOP-002-2a	R2.		Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study	MEDIUM	BA, TOP		x								

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TOP-002-2a	R3.		Each Load-Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	MEDIUM	BA, GOP, LSE, TSP		x			A					X
TOP-002-2a	R4.		Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal	MEDIUM	BA, TOP		x								
TOP-002-2a	R5.		Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange	MEDIUM	BA, TOP		x								
TOP-002-2a	R6.		Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	MEDIUM	BA, TOP		x								X
TOP-002-2a	R7.		Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single	MEDIUM	BA		x								
TOP-002-2a	R8.		Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	MEDIUM	BA		x								
TOP-002-2a	R9.		Each Balancing Authority shall plan to meet Interchange Schedules and Ramps.	LOWER	BA		x								
TOP-002-2a	R10.		Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating	MEDIUM	BA, TOP		x								
TOP-002-2a	R11.		The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission	MEDIUM	TOP		x			A					X
TOP-002-2a	R12.		The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in	MEDIUM	TSP		x								
TOP-002-2a	R13.		At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that	MEDIUM	GOP		x								
TOP-002-2a	R14.		Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and	MEDIUM	GOP		x								
TOP-002-2a		R14.1.	Changes in real output capabilities. (Effective August 1, 2007)	MEDIUM	GOP		x								
TOP-002-2a		R14.2.	Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	LOWER	GOP		x								

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TOP-002-2a	R15.		Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to	LOWER	GOP		x								
TOP-002-2a	R16.		Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their	MEDIUM	TOP		x								
TOP-002-2a		R16.1.	Changes in transmission facility status.	HIGH	TOP		x								
TOP-002-2a		R16.2.	Changes in transmission facility rating.	HIGH	TOP		x								
TOP-002-2a	R17.		Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16	HIGH	BA, TOP	x									
TOP-002-2a	R18.		Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers, and Load-Serving Entities	MEDIUM	BA, GOP, LSE, TOP, TSP	x				A					X
TOP-002-2a	R19.		Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system	MEDIUM	BA, TOP		x								
TOP-003-1	R1.		Generator Operators and Transmission Operators shall provide planned outage information.	No VRF Assigned	GOP, TOP										
TOP-003-1		R1.1.	Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next	MEDIUM	GOP, TOP										
TOP-003-1		R1.2.	Each Transmission Operator shall provide outage information daily to affected Balancing Authorities and Transmission Operators for scheduled	MEDIUM	RC, TOP										
TOP-003-1		R1.3.	Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western	MEDIUM	GOP, TOP										
TOP-003-1	R2.		Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment,	MEDIUM	BA, GOP, TOP										
TOP-003-1	R3.		Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment	MEDIUM	BA, GOP, TOP										
TOP-003-1	R4.		Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	MEDIUM	RC										
TOP-004-2	R1.		Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	HIGH	TOP		x								
TOP-004-2	R2.		Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe	HIGH	TOP		x								
TOP-004-2	R3.		Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages,	HIGH	TOP		x								

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TOP-004-2	R4.		If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered	HIGH	TOP	x									
TOP-004-2	R5.		Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining	HIGH	TOP		x								
TOP-004-2	R6.		Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:	MEDIUM	TOP			x		A					X
TOP-004-2		R6.1.	Monitoring and controlling voltage levels and real and reactive power flows.	MEDIUM	TOP			x		A					X
TOP-004-2		R6.2.	Switching transmission elements.	MEDIUM	TOP			x		A					X
TOP-004-2		R6.3.	Planned outages of transmission elements.	MEDIUM	TOP			x		A					X
TOP-004-2		R6.4.	Responding to IROL and SOL violations.	MEDIUM	TOP			x		A					X
TOP-005-2a	R1.		As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for	Pending	NERC_Net Users							ER			
TOP-005-2a	R2.		Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate	Pending	BA, TOP							ER			
TOP-005-2a	R3.		Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them	Pending	PSE							ER			
TOP-006-2	R1.		Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.	MEDIUM	BA, TOP										
TOP-006-2		R1.1.	Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.	MEDIUM	GOP										
TOP-006-2		R1.2.	Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission	MEDIUM	BA, TOP										
TOP-006-2	R2.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and	HIGH	BA, RC, TOP										
TOP-006-2	R3.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning	MEDIUM	BA, RC, TOP										
TOP-006-2	R4.		Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to	MEDIUM	BA, TOP										

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TOP-006-2	R5.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of	MEDIUM	BA, RC, TOP										
TOP-006-2	R6.		Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if	HIGH	BA, TOP										
TOP-006-2	R7.		Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	HIGH	BA, RC, TOP										
TOP-007-0	R1.		A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to	HIGH	TOP		x					ER			
TOP-007-0	R2.		Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as	HIGH	TOP		x					ER			
TOP-007-0	R3.		A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply	HIGH	TOP	x									
TOP-007-0	R4.		The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions	HIGH	RC		x					ER			
TOP-008-1	R1.		The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include	HIGH	TOP		x								
TOP-008-1	R2.		Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its	HIGH	TOP		x								
TOP-008-1	R3.		The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition	HIGH	TOP		x								
TOP-008-1	R4.		The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be	MEDIUM	TOP		x								
			TRANSMISSION PLANNING												
TPL-001-0.1	R1.		The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in	HIGH	PA, PC, TP										
TPL-001-0.1		R1.1.	Be made annually.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.1.	Cover critical system conditions and study years as deemed appropriate by the entity performing the study.	MEDIUM	PA, PC, TP										

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TPL-001-0.1		R1.3.2.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.3.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.4.	Have established normal (pre-contingency) operating procedures in place.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.5.	Have all projected firm transfers modeled.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.6.	Be performed for selected demand levels over the range of forecast system demands.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.7.	Demonstrate that system performance meets Table 1 for Category A (no contingencies).	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.8.	Include existing and planned facilities.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R1.4.	Address any planned upgrades needed to meet the performance requirements of Category A.	MEDIUM	PA, PC, TP										
TPL-001-0.1	R2.		When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and	MEDIUM	PA, PC, TP										
TPL-001-0.1		R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R2.1.1.	Including a schedule for implementation.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM	PA, PC, TP										
TPL-001-0.1		R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed	LOWER	PA, PC, TP										
TPL-001-0.1	R3.		The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and	LOWER	PA, PC, TP						A				
TPL-002-0a	R1.		The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected	HIGH	PA, PC, TP			x							X

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TPL-002-0a		R1.1.	Be made annually.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.1.	Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.11.	Include the effects of existing and planned control devices.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.5.	Have all projected firm transfers modeled.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system Demands.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.7.	Demonstrate that system performance meets Category B contingencies.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.8.	Include existing and planned facilities.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.4.	Address any planned upgrades needed to meet the performance requirements of Category B of Table I.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R1.5.	Consider all contingencies applicable to Category B.	MEDIUM	PA, PC, TP			x							X

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
TPL-002-0a	R2.		When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R2.1.1.	Including a schedule for implementation.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM	PA, PC, TP			x							X
TPL-002-0a		R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed	MEDIUM	PA, PC, TP			x							X
TPL-002-0a	R3.		The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and	LOWER	PA, PC, TP		x				A				
TPL-003-0a	R1.		The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected	HIGH	PA, PC, TP			x							X
TPL-003-0a		R1.1.	Be made annually.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.1.	Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.11.	Include the effects of existing and planned control devices.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM	PA, PC, TP			x							X

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
TPL-003-0a		R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.5.	Have all projected firm transfers modeled.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system demands.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.7.	Demonstrate that System performance meets Table 1 for Category C contingencies.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.8.	Include existing and planned facilities.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.4.	Address any planned upgrades needed to meet the performance requirements of Category C.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a		R1.5.	Consider all contingencies applicable to Category C.	MEDIUM	PA, PC, TP			x							X
TPL-003-0a	R2.		When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and	MEDIUM	PA, PC, TP		x								
TPL-003-0a		R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM	PA, PC, TP		x								
TPL-003-0a		R2.1.1.	Including a schedule for implementation.	MEDIUM	PA, PC, TP		x								
TPL-003-0a		R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM	PA, PC, TP		x								
TPL-003-0a		R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM	PA, PC, TP		x								
TPL-003-0a		R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed	MEDIUM	PA, PC, TP		x								
TPL-003-0a	R3.		The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and	LOWER	PA, PC, TP	x					A				
TPL-004-0	R1.		The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.1.	Be made annually.	MEDIUM	PA, PC, TP		x								

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
TPL-004-0		R1.2.	Be conducted for near-term (years one through five).	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.1.	Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.4.	Have all projected firm transfers modeled.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.5.	Include existing and planned facilities.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.6.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.7.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.8.	Include the effects of existing and planned control devices.	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.3.9.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand	MEDIUM	PA, PC, TP		x								
TPL-004-0		R1.4.	Consider all contingencies applicable to Category D.	MEDIUM	PA, PC, TP		x								
TPL-004-0	R2.		The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide	LOWER	PA, PC, TP	x					A				
			VOLTAGE AND REACTIVE												
VAR-001-2	R1.		Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed,	HIGH	TOP		x			A					X
VAR-001-2	R2.		Each Transmission Operator shall acquire sufficient reactive resources – which may include, but is not limited to, reactive generation scheduling;	HIGH	TOP		x			A					X
VAR-001-2	R3.		The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and	LOWER	TOP			x		A					X

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
VAR-001-2		R3.1.	Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.	LOWER	TOP			x		A					X
VAR-001-2		R3.2.	For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.	LOWER	TOP			x		A					X
VAR-001-2	R4.		Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the	MEDIUM	TOP		x			A					X
VAR-001-2	R5.		Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited	HIGH	LSE, PSE			x							
VAR-001-2	R6.		The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system	MEDIUM	TOP			x		A					X
VAR-001-2		R6.1.	When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or	MEDIUM	TOP			x		A					X
VAR-001-2	R7.		The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.	HIGH	TOP			x							
VAR-001-2	R8.		Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – which may	HIGH	TOP			x							
VAR-001-2	R9.		Each Transmission Operator shall maintain reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line	HIGH	TOP		x			A					X
VAR-001-2		R9.1.	Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when	HIGH	TOP		x			A					X
VAR-001-2	R10.		Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected	HIGH	TOP			x							
VAR-001-2	R11.		After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide	LOWER	TOP			x							
VAR-001-2	R12.		The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are	HIGH	TOP			x							
VAR-002-1.1b	R1.		The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode	MEDIUM	GOP		x			A					X
VAR-002-1.1b	R2.		Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable	MEDIUM	GOP		x			A					X
VAR-002-1.1b		R2.1.	When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and	MEDIUM	GOP		x			A					X
VAR-002-1.1b		R2.2.	When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.	MEDIUM	GOP		x			A					X

Reliability Standard (FERC Approved)	Requirement Number	Supporting Requirement Number	Text of Requirement	Violation Risk Factor	Functions Monitored	2012 Annual Program Audit - 1st Tier	2012 Annual Program Audit - 2nd Tier	2012 Annual Program Audit - 3rd Tier		Self-Cert. Annual (A)	Periodic Data Submittals: Monthly (M), Quarterly (Q), Annual (A)	Exception Reporting (ER)	Spot Check (SC)		2011 Annual Program Audit (X)
VAR-002-1.1b	R3.		Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:	MEDIUM	GOP		x			A					X
VAR-002-1.1b		R3.1.	A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system	MEDIUM	GOP		x			A					X
VAR-002-1.1b		R3.2.	A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in	MEDIUM	GOP		x			A					X
VAR-002-1.1b	R4.		The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.	LOWER	GO			x							
VAR-002-1.1b		R4.1.	For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:	LOWER	GO			x							
VAR-002-1.1b		R4.1.1.	Tap settings.	LOWER	GO			x							
VAR-002-1.1b		R4.1.2.	Available fixed tap ranges.	LOWER	GO			x							
VAR-002-1.1b		R4.1.3.	Impedance data.	LOWER	GO			x							
VAR-002-1.1b		R4.1.4.	The +/- voltage range with step-change in % for load-tap changing transformers.	LOWER	GO			x							
VAR-002-1.1b	R5.		After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap	MEDIUM	GO			x							
VAR-002-1.1b		R5.1.	If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator	LOWER	GOP			x							
															2011 Total
				2012	Totals	274	398	253		430	51	35	0		462

Revision History

Revision Number	Date	Standard/Process	Description
0	3/18/11	Development	Initial Draft
1	5/12/11	Development	Incorporated feedback for CIPs and 693 Standards
1.1	6/30/11	Production	Final review and approval.
2	7/12/11	Revision	Updated list of Reliability Standards subject to spot check
2.1	8/11/11	Revision	Updated in-effect version for 2012: CIP-005-3a, IRO-004-2, IRO-005-2a, IRO-006-5, IRO-006-EAST-1, and IRO-006-WECC-1. Removed Reliability Standards: MOD-006-0.1 and MOD-007-0.
2.2	8/19/11	Revision	Updated in-effect version for 2012: BAL-006-2, CIP-001-2a, INT-003-3, IRO-005-3a, PER-004-1, PER-004-2, and TOP-005-2a
3	10/19/11	Revision	Updated Summary tab, corrected PRC-004-2 implementation dates, corrected IRO-002-2 R3 applicability, and corrected INT-006-3 links
4	1/9/12	Revision	Removed EOP-001-0 R2 from Tier 2 due to its retirement. Added IRO-009-1 R1 and R2 as Tier 2 requirements. Added PER-003-1 to the list as it becomes enforceable on 10/1/2012. Updated PRC-004-2a to reflect the interpretation added to this standard, which becomes enforceable 4/1/2012.
5	1/17/12	Revision	Updated EOP-001-0 to include the interpretation approved on 12/15/11 to EOP-001-0b. Updated FAC-014-2 requirement detail to include annual self-certification of all requirements in accordance with section D.1.2. of the standard.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Number of Reliability Standards						
Year	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Compliance Audit	39	60	49	56	39	36
Self-Certification	39	60	52	60	53	36
Periodic Data Submittals	--	--	12	13	14	14
Exception Reporting	--	--	14	19	13	13
Spot Check	0	0	13	19	1	0
Subject to Compliance Violation Investigation	--	--	94	95	102	107
Subject to Self-Reporting	--	--	94	95	102	107
Subject to Complaint	--	--	94	95	102	107

2012 CMEP Reliability Standards Summary			
Reliability Standards (FERC Approved)	**Self-Certification Annual (A)**	**Annual Program Audit - Tier 1 (X)**	**Spot Check (SC)**
BAL-001-0.1a			
BAL-002-0 (BAL-002-1 Effective 04/01/2012)		X	
BAL-003-0.1b			
BAL-004-0			
BAL-005-0.1b			
BAL-006-2			
CIP-001-2a	A	X	
CIP-002-3	A	X	
CIP-003-3	A	X	
CIP-004-3	A		
CIP-005-3a	A	X	
CIP-006-3c	A	X	
CIP-007-3	A	X	
CIP-008-3	A	X	
CIP-009-3	A	X	

COM-001-1.1	A	X	
COM-002-2	A	X	
EOP-001-0b	A	X	
EOP-002-3	A	X	
EOP-003-1			
EOP-004-1		X	
EOP-005-1	A	X	
EOP-006-1		X	
EOP-008-0	A	X	
EOP-009-0			
FAC-001-0		X	
FAC-002-1		X	
FAC-003-1	A	X	
FAC-008-1	A		
FAC-009-1	A	X	
FAC-010-2.1			
FAC-011-2			
FAC-013-1			
FAC-014-2	A		
INT-001-3			
INT-003-3			
INT-004-2			
INT-005-3			
INT-006-3			
INT-007-1			
INT-008-3			
INT-009-1			
INT-010-1			
IRO-001-1.1			
IRO-002-2		X	
IRO-003-2			
IRO-004-2	A	X	
IRO-005-3a	A	X	
IRO-006-5			
IRO-006-EAST-1			
IRO-006-WECC-1			
IRO-008-1			
IRO-009-1			
IRO-010-1			
IRO-014-1			

IRO-015-1			
IRO-016-1			
MOD-001-1a	A	X	
MOD-004-1	A	X	
MOD-008-1	A	X	
MOD-010-0			
MOD-012-0			
MOD-016-1.1			
MOD-017-0.1			
MOD-018-0			
MOD-019-0.1			
MOD-020-0			
MOD-021-1			
MOD-028-1			
MOD-029-1a			
MOD-030-2			
NUC-001-2		X	
PER-001-0.1			
PER-002-0	A	X	
PER-003-0 (PER-003-1 Effective 10/1/2012)			
PER-004-1			
PER-004-2			
PER-005-1			
PRC-001-1	A	X	
PRC-004-1 (PRC-004-2a Effective 4/1/2012)	A		
PRC-005-1	A	X	
PRC-007-0			
PRC-008-0	A		
PRC-009-0			
PRC-010-0			
PRC-011-0	A		
PRC-015-0			
PRC-016-0.1			
PRC-017-0	A		
PRC-018-1			
PRC-021-1			
PRC-022-1			
PRC-023-1	A		
TOP-001-1			
TOP-002-2a	A	X	

TOP-003-1			
TOP-004-2	A	X	
TOP-005-2a			
TOP-006-2			
TOP-007-0		X	
TOP-008-1			
TPL-001-0.1			
TPL-002-0a			
TPL-003-0a		X	
TPL-004-0		X	
VAR-001-2	A		
VAR-002-1.1b	A		

Note: The Reliability Standards listed for the above monitoring methods does not necessarily imply all requirements are included in the 2012 Reliability Standard Actively Monitored list. Refer to the "Requirements Detail Tab" for specifics concerning each Reliability Standard monitoring details.

From: Stacia-Ann Chambers
To: Stacia-Ann Chambers
Subject: NERC: Updated 2012 Actively Monitored List
Date: Thursday, January 19, 2012 12:57:39 PM
Importance: High

Announcement

Updated Actively Monitored List

Minor Revision

January 19, 2012

Click here for: 2012 Actively Monitored List **Updated Link**

Ladies and Gentlemen:

NERC Compliance Operations has updated the 2012 Actively Monitored List to take into account the recent adoption of an interpretation to EOP-001-0 on 12/15/2011, making the current version EOP-001-0b. Additionally, the Actively Monitored List has been corrected within the requirement detail tab with respect to the annual self-certification of all requirements within FAC-014-2 in accordance with section D.1.2. of the standard. The Summary tab of the Actively Monitored List has accurately identified FAC-014-2 as subject to annual self-certification while the Requirement Detail tab did not.

As a note, these revisions have resulted in no change for any of the three tiers within the Actively Monitored List.

For more information or assistance, please contact Kyle Howells or Jim Hughes (via email).

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NPCC Standards Development Process Questionnaire

Reply prepared by Consolidated Edison Co. of NY, Inc.

January 25th, 2012

1) What is currently working to your satisfaction in the current process?

Reply:

- The NERC Standards are being developed and approved by stakeholders. This practice should be continued.
- Stakeholders are generally represented by industry experts.

2) What in the current process does not seem to be efficient and effective?

Reply:

- CANs – There is not a clear connection between CAN's and promoting changes/improvements in specific reliability standards by drafting teams. One of the first charges given drafting teams should be to review relevant CANs for applicability to their task. The drafting teams should address all relevant CAN's issues as part of their work scope.
- DT Voting: Some drafting teams (DT's) seem to decide issues by Chair-declared consensus. Few, if any votes are actually taken. So, it is sometimes unclear whether the DT member votes/views have been gauged correctly and recorded. The NERC Facilitators should be instructed in Robert's Rules of Order and should apply them professionally, whenever required. The NERC Facilitators should instruct DT members in Robert's rules, such as calling the question. The DT Chair and NERC Facilitators should never be granted the discretion of declaring a consensus without at minimum a show of hands vote, including a voice vote for members who have called-in. The record of every member vote by member should be recorded in the minutes of the Drafting Team.
- Replies to Formal Comments: Drafting teams (DT) frequently do not reply directly to individual formal comments. Their replies have at times been generic and not on point. Often the linkage between proposed reliability standard wording changes and DT replies to industry comments are tenuous at best. Rigorous standards of evidence, weight and predominance of concern should be established to guide all drafting teams. This will assure that all important industry-wide concerns are addressed.
- DT Membership: Drafting team (DT) membership should be drawn from subject matter experts (SMEs) in the areas to be addressed by the standard DT. Those with asset-owning, design, operating, manufacturing and maintenance experience should be preferred to and promoted over those volunteers with regulatory or legal backgrounds and experience. Regulator and non-technical membership on drafting teams should be limited to no more than 10%. They may send staff as observers, but voting drafting team membership should be limited. The Chair should always be an SME from industry. It is inappropriate to have too many non-SME's making critical technical decisions and recommendations concerning areas in which they have little or no prior expertise or experience.

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- Communications Resources: NERC Drafting Teams (DTs) typically do not offer webinar services during DT meetings. This is practiced in the Regions very effectively. NERC needs to use this technology more effectively. Also, phone-in set-ups are typically second rate. Speakers cannot be heard and call-in members cannot participate fully. Some DTs put call-in members and observers on mute for extended periods, perhaps with the exception of brief call-in comment periods. This practice severely limits the ability of call-in members and observers to participate fully and engage effectively in DT meeting discussions.

3) Identify what potential revisions to the process might be and how they may impact the result.

Reply (see replies to Question 2 above):

- Drafting Team Membership:
    - Establish more stringent requirements for membership regarding experience and relevance to the drafting team assignment for subject matter experts.
    - Limit Drafting Team non-SME's, non-Segment and non-asset-owning/planning/operating members to 10%. They may send staff as observers, but DT membership should be limited principally to SME's.
    - Require that the Chair and NERC Facilitator be a qualified SME's in the reliability standard area(s) to be addressed, e.g., relay protection, CIP's or Communications.
- Drafting Team Rules: Drafting teams (DTs) should be required to adhere to Robert's Rule of Order when deciding important matters. The NERC Facilitators should be instructed in Robert's Rules of Order and should apply them professionally whenever required. The NERC Facilitators should instruct DT members in such rules, such as calling the question. The DT Chair and NERC Facilitators should only declare a consensus with, at minimum, a show of hands vote, including a voice vote for members who have called-in. The record of every member vote by member should be recorded in the minutes of the Drafting Team.
- Call-In Services: NERC should offer Webinar services to all call-in members and observers for all DT meetings. Call-in members and observers should not be placed on 'mute' blocking their participation for extended periods of time during drafting team sessions.
- DT Reply to Comments: Each drafting team should be required to reply to formal comments on a specific point-counterpoint basis addressing the entire specific comment of each contributor. The excessive use of generic replies should be discouraged. All changes to proposed standard wording should be tied to specific formal comment(s) received and on-point replies provided. The linkage back to industry comments and DT replies must be easily identifiable and not generic or vague. Any proposed standard wording change(s) proposed by the DT should address the specific comment received and reply made.

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4) What can NERC staff do to improve their use of resources? For the regions?

- NERC Facilitator and Member Training & Comportment:
  - The NERC Facilitators should be instructed in Robert's Rules of Order and should apply them as required.
  - The NERC Facilitators should instruct DT members in Robert's Rules, such as calling the question.
  - The DT Chair and NERC Facilitators should never be granted the discretion of declaring a consensus without at minimum a show of hands vote, including a voice vote for members who have called-in.
- NERC Call-in and Webinar Resources:
  - NERC should offer Webinar services to all call-in members and observers for all DT meetings.
  - Fully functional call-in services should be provided. Too often a member or observer calling-in cannot hear in-person member discussions preventing their effective participation.
  - Call-in drafting team members and observers should not be placed on 'mute' blocking their participation for extended periods of time during drafting team sessions.
- For Regions:
  - See Training and Call-in comments above.

5) Productivity seems to be at issue. Currently a standard takes on average of 40 months to develop and NERC wants it take 12 months. I find a strictly time oriented [approach], as opposed to quality oriented focus, potentially problematic. In the end, standards that were developed quicker may end up with more directives from FERC. What are the current roadblocks? i.e. NERC's lack of resources, FERC reviews, complexity of the process, the ANSI paradigm etc. ...

Reply:

- Projects: We are concerned when NERC often combines several Standards into a single Project, and then seeks to close-out the Project in less time. It may be reasonable for NERC to place a 12 month limit on small projects, but unreasonable for larger projects. Perhaps, projects should be scored by level of complexity and urgency and placed on a sliding time scale? Complexity would allow more time, whereas greater urgency would shorten the time available. Simple urgent project would be complete quickest. Complex, lower priority, less urgent projects would be allowed more time.
- Comment, Voting and Drafting Team Replies: Somewhat shortened industry comment and voting periods and shorter drafting team reply periods may be possible. Could 30 day comment periods be adopted, with balloting during the last 5 days? 30 days seems to work for informal comment periods. A shorter comment consideration time period, limiting drafting team replies periods to say 15-30 days (depending on Project complexity) would also help.

DRAFT

6) I would like to also explore how we have a more open exchange with the FERC staff to get their concerns addressed sooner rather than after filing. Ideas?

Reply:

- Drafting Team Liaisons: The BES SDT had at least one FERC and NERC Staff member in attendance at all DT meetings. Each would give their respective entity positions. This was helpful in getting an advance read on FERC's Staff and NERC Staff's concerns and positions.
- Written Comments by Regulators: Written comment submissions by NERC and FERC Staff would be helpful in allowing them to formulate and present their positions and make them known to industry. Regulator comment inputs should be encouraged.

7) Is there a broader coordination that can be done across industry sectors to help formulate and address comments earlier? Can the Regions take a more active [role] in "inter-regional" review?

Reply:

- NPCC has been very active and effective in preparation of Region-wide comments. Continued coordination with regard to getting region members on drafting teams is recommended.

DRAFT

From: Guy V. Zito
To: rscmembers
Subject: Standards Development Process
Date: Monday, January 23, 2012 12:05:35 PM

RSC Members,

NPCC participated in a brief teleconference on Friday consisting of Industry Trade Groups, NERC Staff and the Regions. NERC will be collecting over the next week and a half until the end of the month on the existing NERC Standards Development Process. Information we would like to build a consensus on is the following at a minimum;

1) What is currently working to your satisfaction in the current process?
2) What in the current process does not seem to be efficient and effective?
3) Identify what potential revisions to the process might be and how they may impact the result.
4) What can NERC staff do to improve their use of resources? the regions?
5) Productivity seems to be at issue. Currently a standard takes on average of 40 months to develop and NERC wants it take 12 months. I find a strictly time oriented as opposed to quality oriented focus potentially problematic. In the end, standards that were developed quicker may end up with more directives from FERC. What are the current roadblocks? i.e. NERC's lack of resources, FERC reviews, complexity of the process, the ANSI paradigm etc....
6) I would like to also explore how we have a more open exchange with the FERC staff to get their concerns addressed sooner rather than after filing. Ideas?
7) Is the a broader coordination that can be done across industry sectors to help formulate and address comments earlier? Can the Regions take a more active in "inter-regional" review?

Please start thinking about the above and NPCC will be providing some input as well. The solicitation of comments has not been publicly made however we will try to respond on behalf of our members and coordinate the concerns and suggestions. Please respond with any comments to the above points by Thursday January 26th. Lee and I will decide the course of action based on concern. In the interim we should set up a teleconference tentatively, based on need for Friday the 27th at 10am. Lee please develop a short agenda and send out call-in information.

Best Regards,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Cedar Creek Wind Energy, LLC	)	Docket No. RC11-1-___
	)	
Milford Wind Corridor Phase I, LLC	)	Docket No. RC11-2-___

ANSWER OF NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

The North American Electric Reliability Corporation ("NERC") submits an answer to the comments filed in the above dockets on December 23, 2011 ("Comments") by the Electric Power Supply Association ("EPSA"), the Edison Electric Institute ("EEI") and the American Wind Energy Association ("AWEA") (collectively, "Commenters").[1]

In orders issued on June 16 and November 17, 2011, the Commission directed NERC to submit for approval a compliance filing that included Reliability Standards applicable to two registered entities: Cedar Creek Wind Energy, LLC ("Cedar Creek") and Milford Wind Corridor Phase I, LLC ("Milford"), and identified certain specific Reliability Standards to be included in that list along with additional ones, as needed. The Commission properly declined to prejudge the outcome of reliability standard development process projects underway on a more generic basis.[2]

On December 2, 2011, NERC submitted a compliance filing in these proceedings ("Compliance Fling") which included a list of Reliability Standards applicable to Cedar Creek and Milford. The Compliance Filing also included a number of agreed upon provisions including those that indicate the circumstances under which the list of applicable standards

[1] To the extent necessary, NERC requests leave to file this answer pursuant to Rules 212 and 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.212 and 213. This answer will provide information that will assist the Commission in its decision-making process.
[2] *Cedar Creek Wind Energy, LLC et al.*, 135 FERC ¶ 61,241 (2011) ("June 16 Order") and *Cedar Creek Wind Energy, LLC et al.*, 137 FERC ¶ 61,141 (2011) ("November 17 Order").

would be revised. Notably, the Compliance Filing notes that the list of applicable Reliability Standards was subject to revision as a result of applicable FERC orders that relate to existing, pending or new Reliability Standards and requirements, applicable to a TO or TOP function.[3] In addition, the Compliance Filing notes that, if future initiatives result in a minimum list of applicable Reliability Standards that are different from the one included in the Compliance Filing, the parties would request necessary approvals to modify the list applicable to Cedar Creek and Milford.

Yet, Commenters have asked the Commission to reject a portion of the list of applicable Reliability Standards included in the Compliance Filing and have expressed concern regarding the provisions related to future modifications to the list of applicable Reliability Standards. Specifically, Commenters request that the Commission direct NERC to "implement the entire scope of Project 2010-07 – Generator Requirements at the Transmission Interface ("Project 2010-07")"[4] rather than the list the parties were directed to negotiate and file in accordance with the Commission's orders.[5] Commenters also request that the Commission provide guidance regarding a draft directive related to the applicability of Reliability Standards to owners and operators of certain types of transmission facilities that is currently being discussed at NERC. These requests are inappropriate and should be rejected by the Commission for a number of reasons.

First, the instant dockets are not the proper forum to resolve any issues related to Project 2010-07 or the current draft directive, which are initiatives designed to address the issue of Reliability Standards applicable to generator owners and operators that own and operate certain types of transmission facilities on a generic basis. In fact, the scope of the instant dockets is

[3] Compliance Filing at p. 2.
[4] Comments at p. 2.
[5] Compliance Filing at p. 4.

clearly limited to resolving the scope of the Reliability Standards that should apply to Cedar Creek and Milford.[6] Therefore, the Commenters' references to Project 2010-07 and their request that the Commission direct NERC to adopt Project 2010-07 exceed the scope of the issues being decided in this case as well as the scope of the Compliance Filing. They are also a collateral attack on the prior orders in these dockets which made it abundantly clear that these issues would not be addressed here.

Project 2010-07 is being developed in accordance with the NERC Rules of Procedure and any modifications to Reliability Standards that result from the project will be brought to the Commission at the appropriate time. Similarly, any issues related to the scope of Project 2010-07 can and should be addressed at that time. As the Commission recognized in the orders issued in the instant dockets, both Cedar Creek and Milford meet the criteria for registration as transmission owners and operators and, therefore, should be subject to certain Reliability Standards applicable to those functions as of the date of their registration.[7] The application of a set of Reliability Standards that may become effective at a future date upon the completion of Project 2010-07 to these entities or any others is not appropriately before the Commission in these proceedings.

As a result, it is premature to discuss the scope of Project 2010-07 in these proceedings. It is also inappropriate to address these issues that are outside of the scope of these proceedings and the instant Compliance Filing, which is limited to defining the subset of Reliability

[6] *See* November 17 Order at P 27: "The Reliability Standard Requirements that we imposed in these proceedings only apply to Cedar Creek and Milford. That order made no finding as to their applicability to other generator owners or operators. Any generator owner or operator has the opportunity to participate in Project 2010-07 to propose which standards should be applicable to generator interconnection lines;" and June 16 Order at P 90 (recognizing that application of transmission owner/operator Reliability Standards more generally is an issue not appropriately addressed in the context of these two registration appeals.)

[7] November 17 Order at P 20; June 16 Order at PP 58, 71, 87.

Standards applicable immediately to two specific entities that have been registered as transmission owners and operators.

Commenters also request that the Commission provide guidance regarding a draft directive that is being discussed by NERC and the industry as an interim measure to close the existing reliability gap pending the completion of the work in Project 2010-07. Commenters' request for generic guidance regarding the draft direct also is inappropriate because the applicability of Reliability Standards to other entities is beyond the scope of these proceedings.

Overall, the Commenters' concerns regarding how the list of applicable Reliability Standards is to be modified in the future, either as a result of Project 2010-07 or any other initiative, are premature. As the Commenters recognize, modifications to the list of applicable Reliability Standards will require Commission review.[8] Any issues regarding any revised list of applicable standards can and should be raised at the time any revisions are submitted to the Commission.

Moreover, the agreement of the parties in this proceeding regarding the manner in which the list of applicable standards is to be modified is fully consistent with the Commission's orders in this case because it is intended to provide certainty with respect to the scope of the parties' immediate responsibilities that result from the current registration of Milford and Cedar Creek as transmission owners and operators recognizing there are efforts underway to address the issue of Reliability Standards applicable to generator owners and operators owning and operating transmission facilities on a industry-wide basis.[9] Consistent with the Commission's orders, the Compliance Filing does not prejudge the outcome of any such efforts or how they would result in

[8] Comments at p. 2.
[9] June 16 Order at P 90.

modifications to the applicable list of Reliability Standards for Cedar Creek and Milford or their registration status in the future.

Finally, the list of applicable Reliability Standards submitted as part of the Compliance Filing, as well as the other provisions contained therein reflect the agreement of NERC, Cedar Creek and Milford, and the relevant Regional Entity, the Western Electricity Coordinating Council ("WECC"). The scope of these proceedings, as made clear in the most recent Commission order in this matter, is limited to these two registered entities.[10] Therefore, the Commission should not disrupt the agreement of the affected parties based on the comments of unaffected third parties.

In conclusion, Commenters are merely seeking to anticipate (and apparently have the Commission prejudge) the outcome of Project 2010-07, a process that is taking its course in accordance with the NERC Rules of Procedure and improperly broaden the scope of this matter by requesting that the Commission address industry-wide issues that are not ripe for review. These requests were rejected in prior orders in these proceedings and should be rejected again. As discussed herein, it would be inappropriate and harmful to disrupt the agreed upon resolution of two specific registration appeals which affect only the two registered entities named. For those reasons, the Commission should disregard the comments and accept the Compliance Filing in its entirety.

[10] *See* note 6, above.

Respectfully submitted,

/s/Rebecca J. Michael

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Dated: January 11, 2012

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 11th day of January, 2012.

/s/ Sonia Mendonca
Sonia C. Mendonca
Attorney
North American Electric Reliability Corporation
1325 G Street, N.W.; Suite 600
Washington, DC 20005
(202) 400-3000
sonia.mendonca@nerc.net

From: Margaret Mayora
To: grpStaff
Subject: Fw: New NERC Related Matters (1.17.2012)
Date: Friday, January 20, 2012 8:14:00 PM

FYI.

----- Original Message -----
From: McCarthy, Catherine P. <CMcCarthy@deweyleboeuf.com>
To: cmccarthy@deweyleboeuf.com
Sent: Fri Jan 20 20:01:47 2012
Subject: New NERC Related Matters (1.17.2012)

1. NERC submits this filing to report that the initial Audit activities of the eight Regional Entities are completed and to provide information on its plans to focus efforts to restructure the Regional Entity Audit Program (RR09-7)

On January 6, 2012, NERC reported that it completed the initial Audit activities of the eight Regional Entities in 2011. NERC's Information Filing submitted on December 23, 2010 described the five Regional Entity Audits that were conducted utilizing the Agreed-Upon Procedures ("AUP") approach, as well as the Spot Check approach based on the AUP to be utilized to conduct the remaining three Regional Entity Audits. Since that filing, NERC concluded the remaining three Audits by mid-2010 and posted the results on its web site. NERC has completed and closed out the AUP Spot Checks. While NERC had targeted December 31, 2011 as the date to finalize the restructured Audit program, it has determined that such efforts should be finalized following the conclusion of the FERC Audit of NERC now underway in FERC Docket NO. FA11-21-000.

http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13985721 <http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13985721>

2. NERC submits an answer to the comments by the Electric Power Supply Association, the Edison Electric Institute and the American Wind Energy Association, regarding Cedar Creek and Milford filed on December 23, 2011 (RC11-1)

On January 11, 2012, NERC submitted an Answer to FERC to the comments filed on December 23, 2011 by the Electric Power Supply Association, the Edison Electric Institute, and the American Wind Energy Association ("Commenters"). Commenters have asked the Commission to reject a portion of the list of applicable Reliability Standards included in the Compliance Filing and have expressed concern regarding the provisions related to future modifications to the list of applicable Reliability Standards. Commenters also request that the Commission provide guidance regarding a draft directive related to the applicability of Reliability Standards to owners and operators of certain types of transmission facilities that is currently being discussed at NERC. In response, NERC stated that the instant dockets are not proper forum to resolve any issues related to Project 2010-07 or the current draft directive, which are initiatives designed to address the issue of Reliability Standards applicable to generator owners and operators that own and operate certain types of transmission facilities on a generic basis.

http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13986930

BACKGROUND: On December 2, 2011, NERC submitted a compliance filing to FERC in response to the FERC Order issued on June 16, 2011. The June 16th Order upheld the registration of Cedar Creek and Milford in the NERC Compliance Registry for the functions of transmission owner and transmission operator within the WECC region. NERC was directed to submit a compliance filing identifying the applicable TO and TOP Reliability Standards and Requirements applicable to Cedar Creek and Milford. NERC and WECC met with both Cedar Creek and Milford to discuss the applicable Reliability Standards and Requirements in accordance with the June 16 Order. The Compliance filing contains an Attachment A with the reliability requirements that apply to Cedar Creek and Milford only. NERC noted that it is continuing to develop refined guidance in a generic sense to better align appropriate standards for generator owners and generator operators that own and operate transmission facilities without general applicability of all TO and TOP standards.

http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13977154

On November 17, 2011, FERC issued an Order Denying Rehearing and Partially Granting Clarification with respect to Cedar Creek Wind Energy LLC and Milford Wind Corridor Phase I, LLC. FERC held that Cedar Creek and Milford Wind were properly

included on the NERC Compliance Registry as transmission owners and transmission operators. Several entities that filed requests for rehearing argued that there was no factual support that the generator lines were material to Bulk-Power System reliability. FERC stated that applying the fact-specific analysis that was used in the June 16th Order, Cedar Creek and Milford Wind's facilities were unique and were material to the Bulk-Power System and the reliable operation and maintenance of the interconnection facilities connected to Cedar Creek and Milford generating facilities were material to the reliability of the Bulk-Power System.

http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13972082

On June 16, 2011, the Commission denied the appeals of two registry decisions in which NERC found that two wind generators, Cedar Creek and Milford, were properly included on the NERC Compliance Registry as transmission owners and transmission operators. Although the ruling is specific to Cedar Creek and Milford, FERC encouraged NERC to work on an approach that would provide guidance on when generators must register as a transmission owner and operator. WECC registered Cedar Creek and Milford as transmission owners and transmission operators. Cedar Creek and Milford appealed WECC's decisions to NERC, arguing that their respective tie-line facilities do not fall within NERC's registration criteria as transmission owners and operators. The Commission denied the appeals and affirmed NERC's registry decisions. FERC found that the wind generators operated high voltage tie-lines that moved power from the generating facility to a central switching station and that these lines were material to the bulk power system reliability. On October 6, 2010, NERC upheld WECC's registration of Cedar Creek as a transmission owner and operator. NERC explained that Cedar Creek meets the requirements of the Registry Criteria. In a separate October 6, 2010, decision, NERC upheld WECC's registration of Milford as a transmission owner and operator. NERC concluded that Milford meets the Registry Criteria requirements for owning and operating an integrated transmission element associated with the Bulk-Power System 100 kV or above. On October 27, 2010, Milford filed its request for appeal of the NERC's Milford Decision.

http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13939112

3. Compliance Filing of the NERC in Response to November 17, 2011 Order Approving Reliability Standard FAC-012-2- Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon (RD11-3)

On January 17, 2012, NERC filed a Compliance Filing in response to the November 17, 2011 Order Approving Reliability Standard FAC-012-2- Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon. In the November 17 Order, FERC directed NERC to (1) modify the VSL language for R1; (2) either (a) revise the VRFs for FAC-013-2 Requirement R1 from a "Lower" designation to a "Medium" designation, or (b) provide additional justification for a "Lower" VRF designation; and (3) submit a compliance filing within 60 days reflecting such revision.

http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13988129

BACKGROUND: On November 17, 2011, FERC issued an Order approving reliability standard FAC-103-12 dealing with the Assessment of Transfer Capability for the Near-Term Transmission Plan Horizon. FERC also found that the violation risk factors (VRFs) assigned the requirements are consistent with the Commission's established guidelines and approve them as filed. However, we find that NERC has not adequately justified its proposed "lower" VRF designation for Requirements R1 and R4, and direct NERC to either provide additional justification for these VRF designations or propose a revised VRF designation that addresses our concerns.

http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13972009

4. Compliance Filing of the NERC in Response to November 17, 2011 Order Approving Reliability Standard FAC-008-3- Facility Ratings (RD11-10)

On January 17, 2012, NERC filed a Compliance Filing in Response to November 17, 2011 Order Approving Reliability Standard FAC-008-3- Facility Ratings. On November 17, 2011, FERC issued an Order approving Reliability Standard FAC-008-3 and directing NERC to file a revision to one VRF for Reliability Standard FAC-008-3 Requirement R2 ("November 17 Order"). In the November 17 Order, FERC directed NERC to revise the VRF for FAC-008-3 Requirement R2 from a "Lower" designation to a "Medium" designation and submit a compliance filing within 60 days reflecting such revisions. Requirement R2 mandates

the provision of the underlying assumptions and methods used to determine the equipment ratings and the process for determining the equipment ratings. NERC proposes to change the VRF for FAC-008-3 Requirement from a "Lower" designation to a "Medium" designation in compliance with the November 17 Order.

http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13988130

BACKGROUND: On November 17, 2011, FERC issued an Order approving reliability standard dealing with Facility Ratings and Facility Ratings Methodology. NERC filed a petition to FERC requesting approval of Reliability Standard FAC-008-3 (Facility Ratings), the associated Violation Risk Factors (VRF) and Violation Severity Levels (VSL), and retirement of Reliability Standards FAC-008-1 (Facility Ratings Methodology) and FAC-009-1 (Establish and Communicate Facility Ratings). Reliability Standard FAC-008-3 creates requirements that obligate transmission owners and generator owners to develop facility ratings methodologies for its facilities.

http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13971989

On June 15, 2011, NERC filed a petition requesting approval of Reliability Standard FAC-008-3, the associated VRFs and VSLs for this Reliability Standard, and retirement of Reliability Standards FAC-008-1 and FAC-009-1. NERC states that it developed Reliability Standard FAC-008-3 using the NERC Reliability Standards Development Procedure, and further states that FAC-008-3 addresses all three Commission directives from Order No. 693. Proposed Reliability Standard FAC-008-3 was approved by the NERC Board of Trustees.

==========

Pursuant to U.S. Treasury Department Circular 230, unless we expressly state otherwise, any tax advice contained in this communication (including any attachments) was not intended or written to be used, and cannot be used, for the purpose of (i) avoiding tax-related penalties or (ii) promoting, marketing or recommending to another party any matter(s) addressed herein.

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==========

From: Guy V. Zito
To: Lee R. Pedowicz
Subject: FW: NERC: Standards Development Process and Cybersecurity Standards Forum
Date: Monday, January 23, 2012 12:23:57 PM

We should have this on the agenda for the next RSC meeting.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

_____
From: david.kiguel@HydroOne.com [david.kiguel@HydroOne.com]
Sent: Wednesday, January 18, 2012 9:01 AM
To: ben@benli.ca; Guy V. Zito; Gerard J. Dunbar; carol.sedewitz@us.ngrid.com; diane_barney@dps.state.ny.us
Subject: RE: NERC: Standards Development Process and Cybersecurity Standards Forum

Another interesting twist on NERC's plans to hold a Standards Summit unfolded yesterday. The NERC Electricity Sub-Sector Coordinating Council held a conference call this afternoon. During this call, Gerry Cauley reported that the summit has been deferred in order to allow several things to happen first:

1. NERC will prepare formal problem statements with respect to CIP standards and the standards development process in general. NERC plans to release these statements publicly by end of January, and wants CEOs and industry leaders to review and discuss them.

2. NERC then plans to convene small focus groups, divided by sector, to review these problem statements. (Gerry mentioned approaching trade associations and Canadians as part of this effort). Through these focus groups, Gerry hopes to have frank conversations at the CEO level to see if NERC and stakeholders can get convergence on problems, issues and viable paths forward. It is hoped that this work can be completed through March.

3. Pending completion of this work, NERC intends to re-schedule the Standards Summit and hold it as a public forum. April was identified as a possible target date.

We should keep an eye to monitor how this evolves.

David

-----Original Message-----
From: Ben Li Associates [mailto:ben@benli.ca]
Sent: Saturday, January 14, 2012 8:19 PM
To: 'Guy V. Zito'; KIGUEL David; 'Gerard J. Dunbar'; carol.sedewitz@us.ngrid.com; diane_barney@dps.state.ny.us
Subject: RE: NERC: Standards Development Process and Cybersecurity Standards Forum

I agree. At the SC meeting, most asks for a root cause analysis to identify

what is really wrong, if any, with the current process. Until this is done, any proposal for a revised or completely revamp process is inappropriate.

Ben

-----Original Message-----
From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: Saturday, January 14, 2012 8:16 PM
To: david.kiguel@HydroOne.com; ben@benli.ca; Gerard J. Dunbar; carol.sedewitz@us.ngrid.com; diane_barney@dps.state.ny.us
Subject: RE: NERC: Standards Development Process and Cybersecurity Standards Forum

Ben,

Yes David is correct. Imperfect as the current process for developing standards is, the industry is comfortable with it and feels like they can participate sufficiently and their opinions considered. Some of what is being envisioned will not be embraced by the industry in my opinion. I would be more than happy to bounce anything off the RSC but at this point don't know where to begin or what processes will make the "first cut" .

Thanks,

Guy V. Zito

Assistant Vice President-Standards

Northeast Power Coordinating Council, Inc.

1040 Avenue of the Americas, 10 th Floor

New York, NY 10018

212-840-1070

212-302-2782 fax

_____

From: david.kiguel@HydroOne.com [david.kiguel@HydroOne.com]

Sent: Saturday, January 14, 2012 1:32 PM

To: ben@benli.ca; Guy V. Zito; Gerard J. Dunbar; carol.sedewitz@us.ngrid.com; diane_barney@dps.state.ny.us

Subject: Re: NERC: Standards Development Process and Cybersecurity Standards Forum

Thank you Ben,

This is an interesting development; a setback for Mr Cauley who personally committed in November to both the MRC and FERC to hold this event.

To me, the SC reaction was fundamental for this development.

The current process, though not perfect, is a success story thanks to the industry, and NERC and regions staff.

David Kiguel

Sent from my BlackBerry. Please excuse my typos.

From: Ben Li Associates [mailto:ben@benli.ca]

Sent: Saturday, January 14, 2012 11:03 AM

To: KIGUEL David; 'Guy V. Zito' <gzito@npcc.org>; 'Gerard J. Dunbar' <gdunbar@npcc.org>; carol.sedewitz@us.ngrid.com <carol.sedewitz@us.ngrid.com>; diane_barney@dps.state.ny.us <diane_barney@dps.state.ny.us>

Subject: FW: NERC: Standards Development Process and Cybersecurity Standards Forum

Interesting development.

Heard some noises about this at the SC meeting, but didn't relay them to you as there wasn't anything concrete.

Don't know the rationale behind it but the SC's concerns and its general view that the proposed process is a non-starter might have been a factor in Cauley's decision to postpone the summit meeting.

Ben

From: Stacia-Ann Chambers [mailto:Stacia-Ann.Chambers@nerc.net]

Sent: Friday, January 13, 2012 09:35 PM

To: trades <trades@listserv.nerc.com<mailto:trades@listserv.nerc.com>>

Subject: NERC: Standards Development Process and Cybersecurity Standards Forum

[cid:image004.jpg@01CCD2AC.29472CC0]

Announcement

Standards Development Process and Cybersecurity Standards Forum

January 13, 2012

Ladies and Gentlemen:

After receiving thoughtful feedback from the industry, NERC is postponing the February 28-29 forum on the Standards Development Process and Cybersecurity Standards. In the interim, we will reach out to industry stakeholders to further develop the issues and alternatives.

For more information or assistance, please contact Mike Moon<mailto:michael.moon@nerc.net> or Herb Schrayshuen<mailto:herb.schrayshuen@nerc.net> (via email).

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

BOARD OF DIRECTORS MEETING

Wednesday, February 1, 2012
8:00 a.m. – Noon
10th Floor - NPCC Offices – New York, NY

Dial-In Available: 877-260-3999 **Code: 6945#**

AGENDA

1. Introductions/Quorum/Antitrust Compliance Guidelines 8:00 a.m.

2. President's Report 8:05 a.m.

3. Consideration of draft NPCC Board of Directors Minutes of November 30, 2011 Meeting 8:15 a.m. *[Action Required]*

4. Committee Reports and Work Plans 8:20 a.m.
   a) Committee Membership Changes *[Action Required]*
   b) Approval of Committee Scopes *[Action Required]*
   c) Approval of Committee Work Plans *[Action Required]*

5. 2011 Corporate Goal Attainment 9:00 a.m.
   a) MDCC Recommendations *[Action Required]*
   (Committee Resolutions to be distributed at meeting)

6. Discussion of proposed NPCC 2012 Corporate Goals 9:30 a.m.
   (Consideration by subsequent email ballot)

7. Organizational Matters 10:00 a.m.
   a) Management Development and Compensation Committee Activities
   b) NERC & Regional Entity Presidents' 2012 Strategy Session

8. NERC Matters 10:30 a.m.
   a) Remarks from NERC Trustee Jan Schori
   b) Member Representatives Committee and Board of Trustees – February 8-9, 2012 Agenda (to be distributed by NERC on January 26th, 2012)
   c) NPCC BOD Policy Input *[Action Required]*

9. Report by the Treasurer 11:20 a.m.
   a) Year End Results (unaudited)
   b) Finance and Audit Committee Activities

10. Administrative Matters 11:30 a.m.
    a) Annual Code of Conduct Implementation
    b) Office of Enforcement of FERC – Audit of NPCC

11. 2012 Board of Director Meeting Dates 11:55 p.m.
    - Tuesday, March 13, 2012 –Tentative BES Teleconference (10 a.m. – 11 a.m.)
    - Tuesday, May 1, 2012 – Teleconference (10 a.m. – 1 p.m.)
    - Tuesday, June 26, 2012 – NPCC Offices (10 a.m. – 3 p.m.)
    - Tuesday, August 7, 2012 – Teleconference (10 a.m. – 1 p.m.)
    - Wednesday, September 19, 2012 – NPCC Offices (10 a.m. – 3 p.m.)
    - Tuesday, October 30, 2012 – Teleconference (10 a.m. – 1 p.m.)
    - Wednesday, November 28, 2012 – Montreal, Quebec (7:30 a.m. – 10 a.m.)

In Camera Session

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

Northeast Power Coordinating Council, Inc. (NPCC)

Chairman: **Harvey J. Reed**
President and CEO: **Edward A. Schwerdt**
Chief Operating Officer: **Jennifer Budd Mattiello**
Secretary: **Andrianne S. Payson, Esq.**
Treasurer: **Christopher Weir, CPA**

DIRECTORS

SECTOR 1 – Transmisson Owners
William G. Longhi (O&R)
André Boulanger (HQ TE)

SECTOR 2 – Reliability Coordinators
Peter Brandien (ISO-NE)
Bruce B. Campbell (IESO)

SECTOR 3 – TDUs, Dist., LSEs
David H. Boguslawski (Northeast Utilities)
Michael Penstone (Hydro One)

SECTOR 4 – Generator Owners
Andrew Barrett (OPG)
Brad Van Auken (NYPA)

SECTOR 5 – Marketers, Brokers, Aggregators
Glen McCartney (CECG)
Daniel Whyte (Brookfield)

SECTOR 6 – State and Provincial Regulatory and/or Governmental Authorities

Hans Mertens (VT DPS)
Tammy Mitchell (NYS DPS)

SECTOR 7- Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities
Michael Forte (NYSRC)
Jeffrey Fenn – (SGC Engineering)

SECTOR 8 – Independent Directors

Donald L. Correll
Jan L. Newton

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Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Andrianne S. Payson at 212-259-8218.

NPCC, Inc.

President's Report

February 1, 2012

Board of Directors Meeting

NPCC, Inc.

Report Items:

- 2012 Reliability Issues
- Significant Focus Areas
- Desired Accomplishments

Northeast Power Coordinating Council, Inc. Board of Directors Meeting
Draft Minutes for Approval

November 30, 2011 | 7:35 a.m.
Toronto Marriott Bloor Yorkville, Toronto, Ontario

The Chairman called to order a duly noticed meeting of the Board of Directors ("*Board"*) of Northeast Power Coordinating Council, Inc. ("*NPCC*") held on November 30, 2011, at 7:35 a.m. A quorum was declared present during the meeting by the President and CEO, Edward Schwerdt. Andrianne Payson acted as Recording Secretary. The meeting announcement, agenda and list of attendees are attached as **Exhibits A, B, and C**, respectively.

NPCC Antitrust Compliance Guidelines

The Chairman recommended that a reading of the *NPCC Antitrust Compliance Guidelines* that were distributed via email with the Board agenda package and reviewed by Directors upon commencement of the meeting be waived. A motion to waive the reading of the *NPCC Antitrust Compliance Guidelines* was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Minutes

The President and CEO presented for approval a draft of the minutes of the Board teleconference held on October 26, 2011. A motion to approve the minutes of the NPCC Board of Directors teleconference held on October 26, 2011 was duly made, seconded and approved by the majority of Directors in each active Sector of the Board with one abstention.

Future Meetings

The President and CEO presented the schedule of Board meetings for calendar year 2012. He noted that the Board's Strategy Session would be held the afternoon of Monday, January 31, 2012 and that the first Board meeting for the year would follow the next morning on Tuesday, February 1, 2012.

President's Report

The President and CEO presented his report to the Board, which is summarized below.

Bulk Electric System – The President and CEO informed the Board that two NERC recirculation ballots, one for the Bulk Electric System ("*BES*") definition and a second for the criteria to request an exception, closed on November 21, 2011 and were approved by stakeholders. The first ballot approving the BES definition received an 81.32% affirmative vote and the second ballot approving the exception criteria received an 81.48% affirmative vote. The President and CEO noted that from an industry-wide perspective, virtually all of the Canadian "ballot" members either abstained from the vote or voted against the BES definition. He explained that the stakeholder approved BES definition, its related implementation plan and supporting application form for exception requests will be presented to the NERC Board of Trustees ("*BOT*") for adoption and subsequently filed with the regulatory authorities. He noted that the regulatory deadline in FERC Order No. 743 *Revision of the Electric Reliability Organization Definition of Bulk Electric System* and related FERC Order No. 743-A requires that the revised BES definition and the process for handling exceptions be filed by January 25, 2012. He explained that NPCC recently met with FERC senior staff to discuss any concerns that FERC may have regarding implementation of the BES definition within NPCC's geographic footprint in the United States. He further explained that NPCC's informal

meeting with FERC senior staff provided an opportunity for frank discussion and allowed for clarification of the BES exceptions regarding (i) the content of the January 25, 2012 compliance filing, (ii) the criteria for inclusions and exclusions, (iii) the procedure for identification of the new BES facilities, (iv) the process for requesting and granting exceptions, and (v) the issues that will be considered by the industry as part of Phase 2 of the BES project. The President and CEO informed the Board that NPCC faced a significant amount of work in 2012 regarding implementation of the BES definition within NPCC's Canadian Provinces.

NPCC Activities During 2011 – The President and CEO reported that there were several achievements during calendar year 2011, including (i) FERC approval of NPCC's Amended & Restated Bylaws which reflected specific enhancements in NPCC's corporate governance structure, (ii) FERC approval of the expansion of the *Regional Delegation Agreement* to incorporate NPCC's role as the Compliance Enforcement Authority for WECC's Reliability Coordinator function, (iii) the Board's direction to NPCC's Regional Standards Committee to develop and test implement a Cost Effectiveness Analysis Procedure (CEAP), which is the first such explicit evaluation conducted during the development of a Regional Reliability Standard, and (iv) the successful recruitment of independent director candidates for Board consideration and selection. The President and CEO noted that each achievement further supported NPCC in "leading the evolution of reliability assurance within North America." He added that within NERC, NPCC was contributing to ERO-wide efficiency by actively participating in the initial stages of the "Find, Fix, Track and Report" compliance enforcement initiative and by assuming a leadership role in "Phase 2" of the initiative which will incorporate a "find-and-fix-in-the-field" component to compliance auditing. Finally, he noted that NPCC's open and interactive culture of compliance survey, which is approximately 80% complete to date, was recently presented to the NERC BOT Compliance Committee as an example of the foundation upon which an efficient risk-based compliance program could be built.

NPCC Committees

Board Committees – The President and CEO presented for Board approval the 2012 roster of committee members for the Corporate Governance and Nominating Committee ("*CGNC"*), the Finance and Audit Committee ("*FAC'*), the Management Development and Compensation Committee ("*MDCC*") and the Pension Committee, with three modifications: (i) Glen McCartney had volunteered to serve on the MDCC for 2012 and had resigned from the CGNC; (ii) André Boulanger had volunteered to serve on the CGNC for 2012; and (iii) David Boguslawski had volunteered to serve on the CGNC for 2012. A motion to approve the following designation of the members of the CGNC, FAC, MDCC and Pension Committee for 2012 was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board.

CORPORATE GOVERNANCE AND NOMINATING COMMITTEE - 2012

Harvey J. Reed	Board Chair – Chair of CGNC
Andrew Barrett	Board Director
André Boulanger	Board Director
David Boguslawski	Board Director
Edward A. Schwerdt	President and CEO
Andrianne S. Payson	Secretary (non-voting)

FINANCE AND AUDIT COMMITTEE - 2012

Christopher Weir, CPA	Treasurer – Chair of FAC
Peter Brandien	Board Director
Bruce B. Campbell	Board Director
Daniel Whyte	Board Director
Jennifer Budd Mattiello	Vice President and COO
Andrianne S. Payson	Secretary (non-voting)

MANAGEMENT DEVELOPMENT AND COMPENSATION COMMITTEE - 2012

Harvey J. Reed	Board Chair – Chair of MDCC
William G. Longhi	Board Director
Peter Brandien	Board Director
Glen McCartney	Board Director
Andrew J. Fawbush	Assistant Secretary (non-voting)

PENSION COMMITTEE - 2012

Edward A. Schwerdt	President and CEO – Chair of Pension Committee
Robert J. DeAngelo	Assistant Treasurer (Northeast Utilities)
Michael Forte	Board Director
Hans Mertens	Board Director
Michael Penstone	Board Director
Jennifer Budd Mattiello	Vice President and COO
Andrew J. Fawbush	Assistant Secretary (non-voting)

Technical Committees – The President then presented for Board approval the list of members of the Regional Standards Committee ("*RSC*"), the Compliance Committee ("*CC*"), the Reliability Coordinating Committee ("*RCC*") and the Public Information Committee ("PIC") for 2012, with one modification to the RCC: the NextEra Energy Resources representative on the RCC has not yet been designated for 2012. A motion to approve the following revised designation of the members of the RSC, CC, RCC, and PIC for 2012 was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board. In response to questions from the Board, the President and CEO explained that the roster for each NPCC committee was subject to final approval by the Board, but that the membership of NPCC's technical task forces is approved by the RCC.

REGIONAL STANDARDS COMMITTEE - 2012

Chairman	Guy V. Zito, Assistant Vice President – Standards, NPCC
Co-Vice Chairman	Gregory A. Campoli, New York Independent System Operator
Co-Vice Chairman	Michael R. Lombardi, Northeast Utilities

Sector 1 – Transmission Owners

David Kiguel, P. Eng, Hydro One Networks Inc.
Christopher L. de Graffenreid, Consolidated Edison Company of New York, Inc.
Michael Schiavone, National Grid
Randy MacDonald, P.Eng, New Brunswick Power Transmission Corporation
Robert J. Pellegrini, The United Illuminating Company
Sylvain Clermont, Hydro-Québec TransÉnergie
Michael R. Lombardi, Northeast Utilities
Ben Wu, Orange and Rockland Utilities, Inc.

ALTERNATES

Ajay Garg, P. Eng, Hydro One Networks Inc.

Sector 2 – Reliability Coordinators

Donald Weaver, New Brunswick System Operator
Gregory A. Campoli, New York Independent System Operator
Kathleen M. Goodman, ISO New England, Inc.
Tina Teng, Independent Electricity System Operator

ALTERNATES

Scott Berry, Independent Electricity System Operator
Esther Kim, Independent Electricity System Operator

Sector 3 – Transmission Dependent Utilities, Distribution Companies, and Load-Serving Entities

Peter Yost, Consolidated Edison Company of New York, Inc.
Saurabh Saksena, National Grid

ALTERNATES

Anthony LaRusso, National Grid

Sector 4 – Generator Owners

Wayne Sipperly, New York Power Authority
Mike Garton, Dominion Resources Services, Inc.
David Ramklawan, P. Eng., Ontario Power Generation Inc.
Chantel Haswell, FPL Group, Inc.

ALTERNATES

Saul Rojas, New York Power Authority

Sector 5 – Marketers, Brokers, and Aggregators

Bruce Metruck, New York Power Authority
Brian Evans-Mongeon, Utility Services LLC

ALTERNATES

Daniella Piper, New York Power Authority

Sector 6 – State and Provincial Regulatory and/or Governmental Authorities

Diane J. Barney, New York State Public Service Commission, Department of Public Service

Sector 7 – Sub-Regional Reliability Councils, Others and Customers

Alan Adamson, Consultant, New York State Reliability Council, LLC

COMPLIANCE COMMITTEE - 2012

Chairman	Stanley E. Kopman, Assistant Vice President – Compliance, NPCC
Vice Chair	Peter Yost, Consolidated Edison Company of New York, Inc.

Sector 1 – Transmission Owners

Ajay Garg, P. Eng, Hydro One Networks Inc.
William Temple, Northeast Utilities
Sylvain Clermont, P. Eng., Hydro-Québec TransÉnergie
Edward F. Dahill, P.E., National Grid
Peter Yost, Consolidated Edison Company of New York, Inc.
Kim Moulton, Vermont Electric Power Company, Inc.
Edward Bedder, Orange and Rockland Utilities, Inc.
Jonathan Appelbaum, The United Illuminating Company
John Robertson, NSTAR Electric

ALTERNATES

Chris de Graffenreid, Consolidated Edison Company of New York, Inc.
Mark Atkins, Vermont Electric Power Company, Inc.
David Burke, Orange and Rockland Utilities, Inc.
Mike Lombardi, Northeast Utilities
David Kiguel, P. Eng.,Hydro One Networks, Inc.
Michael Bilheimer, The United Illuminating Company

Sector 2 – Reliability Coordinators

Calvin Duncan, P. Eng., New Brunswick System Operator
Gregory Campoli, New York Independent System Operator
Richard Burke, ISO New England, Inc.
Joseph Fox, ing., Hydro-Québec TransÉnergie
Esther Kim, Independent Electricity System Operator

ALTERNATES

Scott Berry, Independent Electricity System Operator (Alternate #1)
Tina Teng, Independent Electricity System Operator (Alternate #2)
Matthew Goldberg, ISO New England, Inc.

Sector 3 – Transmission Dependent Utilities, Distribution Companies, and Load-Serving Entities

Vicki M. O'Leary, National Grid
Ben Wu, Orange and Rockland Utilities, Inc.

ALTERNATES

Michael Jones, National Grid

Sector 4 – Generator Owners

Thomas Czerniewski, Entergy Services, Inc.
Chantel Haswell, NextEra Eneryg Resources, LLC
Mike Garton, Dominion Resources Services, Inc.

ALTERNATES

Michael Gildea, Dominion Resource Services
Brian Murphy, NextEra Energy Resources, LLC

Sector 5 – Marketers, Brokers, and Aggregators

Bruce Metruck, New York Power Authority
Brian Evans-Mongeon, Utility Services, Inc.

ALTERNATES

Wayne Sipperly, New York Power Authority

Sector 6 – State/Provincial Regulatory and/or Governmental Authorities

Randy D. Crissman, New York Power Authority

Sector 7 – Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities

To Be Determined

ALTERNATES

Saul Rojas, New York Power Authority

RELIABILITY COORDINATING COMMITTEE - 2012

Chairman	Donald L. Gates, ISO New England, Inc.
Co-Vice Chairman	Michael Schiavone, National Grid
Co-Vice Chairman	Alden Briggs, New Brunswick System Operator

Sector 1 – Transmission Owners

Randy MacDonald, New Brunswick Power Transmission Corporation
Tony O'Hara, New Brunswick Power Transmission Corporation (Alternate)
Brian Conroy, Central Maine Power Company
David Conroy, Central Maine Power Company (Alternate)
Michael Schiavone, National Grid
Robert J. Pellegrini, The United Illuminating Company
Jonathan Appelbaum, The United Illuminating Company
Paul Renaud, Vermont Electric Power Company, Inc.
Hantz A. Présumé, Vermont Electric Power Company, Inc. (Alternate)
Thomas C. Duffy, Central Hudson Gas & Electric Corporation
Michael Forte, Consolidated Edison Company of New York, Inc.
Peter Yost, Consolidated Edison Company of New York, Inc. (Alternate)
David Clarke Long Island Power Authority
Brad Bentley, Northeast Utilities
Steve DeCarlo, New York Power Authority
Michael Parisi, New York Power Authority (Alternate)
Raymond Kinney, New York State Electric & Gas Corp.
Joseph Fleury, New York State Electric & Gas Corp. (Alternate)
John Allen, Rochester Gas and Electric Corporation
Paul Casey, Nova Scotia Power Inc.
David Sanford, Nova Scotia Power Inc. (Alternate)
Paul Tremblay, Hydro One Networks, Inc.
John Sabiston, Hydro One Networks, Inc. (Alternate)

Sector 2 – Reliability Coordinators

Alden Briggs, New Brunswick System Operator
Donald L. Gates, ISO New England, Inc.
Mike Henderson, ISO New England, Inc. (Alternate)
Dana Walters, New York Independent System Operator
Barbara Constantinescu, Independent Electricity System Operator
Len Kula, Independent Electricity System Operator (Alternate)
Pierre Paquet, Hydro-Québec TransÉnergie

Sector 3 – Transmission Dependent Utilities, Distribution Companies, and Load-Serving Entities

Stéphane Dufresne, Hydro-Québec Distribution
Luc Bernier, Hydro-Québec Distribution (Alternate)
Curt Dahl, Long Island Power Authority
Steve Marron, Long Island Power Authority (Alternate)
Marilyn Brown, New York Power Authority
Andrew Stewart, New York Power Authority (Alternate)

Dwayne Basler, Northeast Utilities

Sector 4 – Generator Owners

Michael Garton, Dominion Resources Services, Inc.
Michael Gildea, Dominion Resources Services, Inc. (Alternate)
Jim Watson, Dynegy, Inc.
Dean Ellis, Dynegy Inc. (Alternate)
Thomas Czerniewski, Entergy Nuclear Northeast, Inc.
To Be Determined, NextEra Energy Resources, LLC
David Appelbaum, NextEra Energy Resources, LLC (Alternate)
Yuri Fisman, Long Island Power Authority
Edward Welz, New York Power Authority
Brad Van Auken, New York Power Authority (Alternate)
David Ramklawan, Ontario Power Generation, Inc.
William Smagula, Northeast Utilities
Drew O'Keefe, Northeast Utilities (Alternate)

Sector 5 – Marketers, Brokers, and Aggregators

Glen McCartney, Constellation Energy Commodities Group, Inc.
Louis Guilbault, Hydro-Québec Energy Services (US) Inc.
Scott Leuthauser, Hydro-Québec Energy Services (US) Inc.
Yannick Vennes, Hydro-Québec Energy Marketing, Inc.
Ben Chu, Long Island Power Authority
William Nadeau, New York Power Authority
William Palazzo, New York Power Authority (Alternate)
Bradley Weghorst, PPL Energy Plus, LLC
Mark Heimbach, PPL Energy Plus, LLC (Alternate)
Brian Evans-Mongeon, Utility Services, LLC
John Helme, Utility Services, LLC

Sector 6 – State and Provincial Regulatory and/or Governmental Authorities

TBA, New York State Department of Public Service
Edward Schrom, Jr., New York State Department of Public Service (Alternate)
Bruce Metruck, New York Power Authority
Wayne Sipperly, New York Power Authority

Sector 7 – Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities

Roger Clayton, New York State Reliability Council, LLC
George C. Loehr, New York State Reliability Council, LLC (Alternate)

PUBLIC INFORMATION COMMITTEE - 2012

Chairman	Steve Allen, Salient Point LLC
Members:	
New England:	Ellen Foley, ISO New England, Inc.
New York:	Michael Clendenin, Consolidated Edison Company of New York, Inc. John Cordi, New York Independent System Operator
PJM:	Ray E. Dotter, PJM Interconnection
Maritimes:	Michel Losier, NB Power Holding Corporation

Midwest ISO:	To be determined
Québec:	To be determined
Ontario:	Terry Young, Independent Electricity System Operator
ReliabilityFirst:	Larry Bugh, ReliabilityFirst Corporation
NERC:	Kimberly Mielcarek, NERC
ALTERNATES	Vera B. Geba, Salient Point LLC
	Gary Paslow, New York Independent System Operator

NPCC Committee Reports – The President and CEO informed the Board that the committee reports would be presented during the Annual Members Meeting scheduled for later that morning.

Designation of NPCC Officers

The President and CEO presented for Board approval the proposed designation of NPCC's officers for 2012. A motion to approve the designation of NPCC's officers for 2012 was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board.

NPCC OFFICERS - 2012

Edward A. Schwerdt	President and CEO
Jennifer Budd Mattiello	Vice President and COO
William G. Longhi	Vice Chairman
Bruce B. Campbell	Vice Chairman
Andrianne S. Payson, Esq.	Secretary
Andrew J. Fawbush, Esq.	Assistant Secretary
Christopher Weir, CPA	Treasurer
Robert J. DeAngelo	Assistant Treasurer

Approval of 2012 NPCC Independent Board Chair

The Board Chair left the meeting. Mr. Longhi then presented the draft Independent Consulting Agreement for NPCC's Independent Board Chair. The President and CEO informed the Board of the changes in the draft Independent Consulting Agreement, which reflected (i) a term that commences on January 1, 2012 and ends on December 31, 2013, and (ii) an increase in the retainer and the services included under the retainer for 2012-2013 to make the agreement for the Board Chair more compatible with the contracts for the NPCC independent directors for the same two-year term. One Board member inquired into the performance review process of the Board Chair for 2011. Several Board members provided their individual assessment of the Board Chair's performance during the past year and Ms. Payson provided summary results of the Board self-assessment questionnaire on this specific item. The Board recommended that going forward the CGNC should provide it with the results of the annual Board self-assessment questionnaire on the performance of the Board Chair for that year and a written summary of the Board Chair's performance for the past year, prior to presenting the Board with the draft Independent Consulting Agreement for the Board Chair. Following further discussion, a motion to retain Mr. Reed as Chairman of the NPCC Board of Directors for 2012-2013 and to approve the Independent Consulting Agreement as presented was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board. The Board Chair then returned to the Board meeting.

Organizational Matters

MDCC Recommendations – The President informed the Board that after discussions with the MDCC, he was recommending to the Board a merit salary increase of 3% effective January 1, 2012 for NPCC Staff, which reflects their significant efforts and achievements this past year. He explained that the proposed 3% increase was consistent with the NPCC budget and with merit salary increases that other Regional Entities had approved for their staff. Mr. Longhi added that based on the research conducted and Regional surveys reviewed by the MDCC, the committee believed that a proposed merit package increase of 3% was consistent with merit package increases approved by other organizations in the industry. The Board Chair noted that the MDCC had endorsed the proposed 3% merit increase and presented draft resolutions for Board review and approval. A motion to approve the MDCC's recommendation of a 3% merit salary increase for NPCC Staff in 2012 was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board with one abstention. Following the vote, the Board briefly discussed the publication of NPCC Board minutes on the Members only section of NPCC's website.

The President and CEO and the Vice President and COO then left the meeting. Mr. Fawbush then joined the meeting via teleconference.

The Board Chair distributed draft Board resolutions with the MDCC's recommendation for the President and CEO's salary increase for 2012. He then provided the Board with an update of recent MDCC activities in connection with the annual performance review of the President and CEO. He explained to the Board that the MDCC met previously to discuss the performance of the President and CEO during 2011 and to review comparable salaries paid to other Regional Entity Presidents. He noted that on behalf of the MDCC, he had conducted a "360 review" by which he had interviewed the "direct reports" of the President and CEO, as well as Board members, other Regional Entity Presidents and NERC Staff members regarding the performance of the President and CEO during 2011. The Board Chair provided a summary of the feedback he received regarding the President and CEO's performance in 2011 and informed the Board that an independent compensation consultant would be retained in 2012 to conduct a compensation review for the President and CEO position as well as the positions held by other senior staff. The Board noted that the MDCC would oversee the work performed by the compensation consultant and requested that the MDCC provide regular updates to the Board of the work performed by the compensation consultant. Several Board members expressed their views regarding the appropriate level of compensation that should be paid to the NPCC President and CEO for 2012, taking into account the salaries paid to other Regional Entity Presidents in a competitive market, NPCC's status as a "quasi-public" not-for-profit corporation in the State of New York, and that the "economy is shrinking" as reflected by the austerity measures implemented by many states. Following discussion, a motion to approve the MDCC's recommendation of an increase in the base salary of the President and CEO was duly made, seconded and approved by the Directors in each active Sector of the Board with one abstention.

Mr. Fawbush left the meeting. The President and CEO and the Vice President and COO then returned to the meeting.

Topics for 2012 Board Strategy Session – The Board Chair informed the Board that he had prepared a list of topics for the upcoming 2012 Board Strategy Session, which included the following: (i) the industry perception of NPCC compared to other Regions and NPCC's steps to reach the "next level" as a Regional Entity; (ii) Board policy positions, particularly if they conflict with positions taken by NPCC members; (iii) the format for written reports submitted by Board committees; (iv) balancing the President and CEO function and the role of the Board; and (v) Board policy or strategic issues for input into the "NERC One Enterprise Planning Process." Board members spent a fair amount of time discussing the perception of NPCC among the other Regional Entities, the relationship between regulators and the industry, and the influence of politics on the relationship between the two groups. The Board agreed to resume thediscussion

of these items during the 2012 Board Strategy Session. The President and CEO asked Board members to submit additional topics for the 2012 Board Strategy Session.

Administrative Matters

Board Self-Assessment – The Board Chair reminded Board members to submit their responses to the NPCC Board 2011 self-assessment matrix. He noted that the results of the Board self-assessment would be discussed in detail during the Board's Strategy Session on January 31, 2012.

Other Matters

FERC Approval of NPCC as WECC Compliance Enforcement Authority – The Board noted the FERC letter dated November 15, 2011 approving NERC's petition for NPCC to serve as the Compliance Enforcement Authority for WECC-registered functions in the United States portion of the WECC Region. The FERC letter was previously circulated in the Board agenda package prior to the Board meeting.

Approval of NPCC Regional Standard PRC-006-NPCC-01 – Mr. Guy Zito, NPCC's Assistant Vice President – Standards, joined the meeting to present the RSC's second proposed Regional Reliability Standard, *Automatic Underfrequency Load Shedding*, for Board consideration and approval. Mr. Zito explained that the RSC started working on the proposed standard in July 2009, and had just completed its third draft, which was posted for comment on the NPCC website on May 6, 2011. He noted that the process to develop the proposed standard included two meetings with NERC, two NERC quality reviews, a presentation to the industry at a Compliance workshop, the development of a Cost Effective Analysis Procedure (CEAP) at the Board's request, and application of the CEAP to the proposed standard to assess its cost impact. He further noted that CEAP was also presented at the North American Generator Forum in Atlanta on October 11, 2011. Mr. Zito informed the Board that there was a completed ballot on November 18, 2011 with an 83% affirmative vote approving the draft regional standard. He explained that Hydro-Québec recently identified a minor correction to the proposed standard, and had requested Board approval of the correction as a non-substantive change to the proposed standard. The Board noted that the error appeared on page 29 of the proposed standard in UFLS Table 4: Québec Interconnection, and that the asterisk in Table 4 should read "Load must be fixed at all times *when above 60% of the peak load*." In response to questions from the Board, Mr. Zito noted the following: (i) he believed that the 2-1/2 years it took to develop the proposed standard would not be the typical timeframe to develop a Regional Standard; and (ii) the CEAP for the proposed standard had an estimated cost of $8 million for the UFLS program change and implementation, which reflects only the capital costs) submitted by the Members who responded to the survey. Mr. Zito explained the $8 million estimate did not reflect the total potential costs of implementation within the NPCC Region by all Members, or include any ongoing maintenance costs. One Board member noted that there was no calculation of the "benefits" that would be realized by the proposed standard and questioned whether the RSC attempted to quantify benefits as part of a cost-benefits analysis for the proposed standard. The Board was informed that, in this instance, the CEAP was applied to a standard already under development and that the reliability need had been identified as a 2003 Blackout recommendation. The Board questioned the feasibility of quantifying the benefits of the proposed standard, but noted that NPCC's work in the reliability area since the 1965 Black-out could attest to the "benefits" realized to date. Following further Board discussion, Mr. Zito agreed to complete a "benefits" assessment as part of CEAP going forward. The Board agreed to continue the cost-benefits analysis discussion during the 2012 Board Strategy Session. A motion to approve the draft *Automatic Underfrequency Load Shedding* Regional Standard PRC-006-NPCC-01 was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Adjournment

There being no further business, the Board Chair adjourned the meeting of the NPCC Board of Directors at 10:20 a.m.

Approved by Board action on _____, 2012.

Submitted by,

_____
Andrianne S. Payson
NPCC Secretary

EXHIBIT C
LIST OF ATTENDEES
November 30, 2011

Present:	Harvey J. Reed, Chairman Edward A. Schwerdt, President and CEO Jennifer Budd Mattiello, Vice President and COO Andrianne S. Payson, Esq., Secretary Andrew J. Fawbush, Esq., Assistant Secretary
	And the following members of the Board of Directors:
Sector 1 (TOs)	William G. Longhi, Orange and Rockland Utilities, Inc. André Boulanger, Hydro-Québec TransÉnergie
Sector 2 (RCs)	Peter Brandien, ISO New England, Inc. Bruce B. Campbell, Independent Electricity System Operator Rick Gonzales, New York Independent System Operator, Inc. (via teleconference)
Sector 3 (TDUs, DCs, LSEs)	David H. Boguslawski, Northeast Utilities Michael Penstone, Hydro One
Sector 4 (GOs)	Andrew Barrett, Ontario Power Generation, Inc.
Sector 5 (Marketers, Brokers and Aggregators)	Glen McCartney, Constellation Energy Commodities Group, Inc. Matthew J. Picardi, Shell Energy NA (by proxy to the President) Daniel Whyte, Brookfield Power Generation
Sector 6 (Customers)	–
Sector 7 (Regulatory)	Hans Mertens, Vermont Department of Public Service Tammy Mitchell, NYS Department of Public Service (via teleconference)
Sector 8 (Others)	Michael Forte, New York State Reliability Council, LLC
Guests	Guy Zito, NPCC Assistant Vice President, Reliability Standards

Northeast Power Coordinating Council, Inc. Board of Directors Meeting
REVISED Draft Minutes for Approval

November 30, 2011 | 7:35 a.m.
Toronto Marriott Bloor Yorkville, Toronto, Ontario

The Chairman called to order a duly noticed meeting of the Board of Directors ("*Board*") of Northeast Power Coordinating Council, Inc. ("*NPCC*") held on November 30, 2011, at 7:35 a.m. A quorum was declared present during the meeting by the President and CEO, Edward Schwerdt. Andrianne Payson acted as Recording Secretary. The meeting announcement, agenda and list of attendees are attached as **Exhibits A, B, and C**, respectively.

NPCC Antitrust Compliance Guidelines

The Chairman recommended that a reading of the *NPCC Antitrust Compliance Guidelines* that were distributed via email with the Board agenda package and reviewed by Directors upon commencement of the meeting be waived. A motion to waive the reading of the *NPCC Antitrust Compliance Guidelines* was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Minutes

The President and CEO presented for approval a draft of the minutes of the Board teleconference held on October 26, 2011. A motion to approve the minutes of the NPCC Board of Directors teleconference held on October 26, 2011 was duly made, seconded and approved by the majority of Directors in each active Sector of the Board with one abstention.

Future Meetings

The President and CEO presented the schedule of Board meetings for calendar year 2012. He noted that the Board's Strategy Session would be held the afternoon of Monday, January 31, 2012 and that the first Board meeting for the year would follow the next morning on Tuesday, February 1, 2012.

President's Report

The President and CEO presented his report to the Board, which is summarized below.

Bulk Electric System – The President and CEO informed the Board that two NERC recirculation ballots, one for the Bulk Electric System ("*BES*") definition and a second for the criteria to request an exception, closed on November 21, 2011 and were approved by stakeholders. The first ballot approving the BES definition received an 81.32% affirmative vote and the second ballot approving the exception criteria received an 81.48% affirmative vote. The President and CEO noted that from an industry-wide perspective, virtually all of the Canadian "ballot" members either abstained from the vote or voted against the BES definition. He explained that the stakeholder approved BES definition, its related implementation plan and supporting application form for exception requests will be presented to the NERC Board of Trustees ("*BOT*") for adoption and subsequently filed with the regulatory authorities. He noted that the regulatory deadline in FERC Order No. 743 *Revision of the Electric Reliability Organization Definition of Bulk Electric System* and related FERC Order No. 743-A requires that the revised BES definition and the process for handling exceptions be filed by January 25, 2012. He explained that NPCC recently met with FERC senior staff to discuss any concerns that FERC may have regarding implementation of the BES definition within NPCC's geographic footprint in the United States. He further explained that NPCC's informal

meeting with FERC senior staff provided an opportunity for frank discussion and allowed for clarification of the BES exceptions regarding (i) the content of the January 25, 2012 compliance filing, (ii) the criteria for inclusions and exclusions, (iii) the procedure for identification of the new BES facilities, (iv) the process for requesting and granting exceptions, and (v) the issues that will be considered by the industry as part of Phase 2 of the BES project. The President and CEO informed the Board that NPCC faced a significant amount of work in 2012 regarding implementation of the BES definition within NPCC's Canadian Provinces.

NPCC Activities During 2011 – The President and CEO reported that there were several achievements during calendar year 2011, including (i) FERC approval of NPCC's Amended & Restated Bylaws which reflected specific enhancements in NPCC's corporate governance structure, (ii) FERC approval of the expansion of the *Regional Delegation Agreement* to incorporate NPCC's role as the Compliance Enforcement Authority for WECC's Reliability Coordinator function, (iii) the Board's direction to NPCC's Regional Standards Committee to develop and test implement a Cost Effectiveness Analysis Procedure (CEAP), which is the first such explicit evaluation conducted during the development of a Regional Reliability Standard, and (iv) the successful recruitment of independent director candidates for Board consideration and selection. The President and CEO noted that each achievement further supported NPCC in "leading the evolution of reliability assurance within North America." He added that within NERC, NPCC was contributing to ERO-wide efficiency by actively participating in the initial stages of the "Find, Fix, Track and Report" compliance enforcement initiative and by assuming a leadership role in "Phase 2" of the initiative which will incorporate a "find-and-fix-in-the-field" component to compliance auditing. Finally, he noted that NPCC's open and interactive culture of compliance survey, which is approximately 80% complete to date, was recently presented to the NERC BOT Compliance Committee as an example of the foundation upon which an efficient risk-based compliance program could be built.

NPCC Committees

Board Committees – The President and CEO presented for Board approval the 2012 roster of committee members for the Corporate Governance and Nominating Committee ("*CGNC"*), the Finance and Audit Committee ("*FAC'*), the Management Development and Compensation Committee ("*MDCC*") and the Pension Committee, with three modifications: (i) Glen McCartney had volunteered to serve on the MDCC for 2012 and had resigned from the CGNC; (ii) André Boulanger had volunteered to serve on the CGNC for 2012; and (iii) David Boguslawski had volunteered to serve on the CGNC for 2012. A motion to approve the following designation of the members of the CGNC, FAC, MDCC and Pension Committee for 2012 was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board.

CORPORATE GOVERNANCE AND NOMINATING COMMITTEE - 2012

Harvey J. Reed	Board Chair – Chair of CGNC
Andrew Barrett	Board Director
André Boulanger	Board Director
David Boguslawski	Board Director
Edward A. Schwerdt	President and CEO
Andrianne S. Payson	Secretary (non-voting)

FINANCE AND AUDIT COMMITTEE - 2012

Christopher Weir, CPA	Treasurer – Chair of FAC
Peter Brandien	Board Director
Bruce B. Campbell	Board Director
Daniel Whyte	Board Director
Jennifer Budd Mattiello	Vice President and COO
Andrianne S. Payson	Secretary (non-voting)

MANAGEMENT DEVELOPMENT AND COMPENSATION COMMITTEE - 2012

Harvey J. Reed	Board Chair – Chair of MDCC
William G. Longhi	Board Director
Peter Brandien	Board Director
Glen McCartney	Board Director
Andrew J. Fawbush	Assistant Secretary (non-voting)

PENSION COMMITTEE - 2012

Edward A. Schwerdt	President and CEO – Chair of Pension Committee
Robert J. DeAngelo	Assistant Treasurer (Northeast Utilities)
Michael Forte	Board Director
Hans Mertens	Board Director
Michael Penstone	Board Director
Jennifer Budd Mattiello	Vice President and COO
Andrew J. Fawbush	Assistant Secretary (non-voting)

Technical Committees – The President then presented for Board approval the list of members of the Regional Standards Committee ("*RSC*"), the Compliance Committee ("*CC*"), the Reliability Coordinating Committee ("*RCC*") and the Public Information Committee ("PIC") for 2012, with one modification to the RCC: the NextEra Energy Resources representative on the RCC has not yet been designated for 2012. A motion to approve the following revised designation of the members of the RSC, CC, RCC, and PIC for 2012 was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board. In response to questions from the Board, the President and CEO explained that the roster for each NPCC committee was subject to final approval by the Board, but that the membership of NPCC's technical task forces is approved by the RCC.

REGIONAL STANDARDS COMMITTEE - 2012

Chairman	Guy V. Zito, Assistant Vice President – Standards, NPCC
Co-Vice Chairman	Gregory A. Campoli, New York Independent System Operator
Co-Vice Chairman	Michael R. Lombardi, Northeast Utilities

Sector 1 – Transmission Owners

David Kiguel, P. Eng, Hydro One Networks Inc.
Christopher L. de Graffenreid, Consolidated Edison Company of New York, Inc.
Michael Schiavone, National Grid
Randy MacDonald, P.Eng, New Brunswick Power Transmission Corporation
Robert J. Pellegrini, The United Illuminating Company
Sylvain Clermont, Hydro-Québec TransÉnergie
Michael R. Lombardi, Northeast Utilities
Ben Wu, Orange and Rockland Utilities, Inc.

ALTERNATES

Ajay Garg, P. Eng, Hydro One Networks Inc.

Sector 2 – Reliability Coordinators

Donald Weaver, New Brunswick System Operator
Gregory A. Campoli, New York Independent System Operator
Kathleen M. Goodman, ISO New England, Inc.
Tina Teng, Independent Electricity System Operator

ALTERNATES

Scott Berry, Independent Electricity System Operator
Esther Kim, Independent Electricity System Operator

Sector 3 – Transmission Dependent Utilities, Distribution Companies, and Load-Serving Entities

Peter Yost, Consolidated Edison Company of New York, Inc.
Saurabh Saksena, National Grid

ALTERNATES

Anthony LaRusso, National Grid

Sector 4 – Generator Owners

Wayne Sipperly, New York Power Authority
Mike Garton, Dominion Resources Services, Inc.
David Ramklawan, P. Eng., Ontario Power Generation Inc.
Chantel Haswell, FPL Group, Inc.

ALTERNATES

Saul Rojas, New York Power Authority

Sector 5 – Marketers, Brokers, and Aggregators

Bruce Metruck, New York Power Authority
Brian Evans-Mongeon, Utility Services LLC

ALTERNATES

Daniella Piper, New York Power Authority

Sector 6 – State and Provincial Regulatory and/or Governmental Authorities

Diane J. Barney, New York State Public Service Commission, Department of Public Service

Sector 7 – Sub-Regional Reliability Councils, Others and Customers

Alan Adamson, Consultant, New York State Reliability Council, LLC

COMPLIANCE COMMITTEE - 2012

Chairman	Stanley E. Kopman, Assistant Vice President – Compliance, NPCC
Vice Chair	Peter Yost, Consolidated Edison Company of New York, Inc.

Sector 1 – Transmission Owners

Ajay Garg, P. Eng, Hydro One Networks Inc.
William Temple, Northeast Utilities
Sylvain Clermont, P. Eng., Hydro-Québec TransÉnergie
Edward F. Dahill, P.E., National Grid
Peter Yost, Consolidated Edison Company of New York, Inc.
Kim Moulton, Vermont Electric Power Company, Inc.
Edward Bedder, Orange and Rockland Utilities, Inc.
Jonathan Appelbaum, The United Illuminating Company
John Robertson, NSTAR Electric

ALTERNATES

Chris de Graffenreid, Consolidated Edison Company of New York, Inc.
Mark Atkins, Vermont Electric Power Company, Inc.
David Burke, Orange and Rockland Utilities, Inc.
Mike Lombardi, Northeast Utilities
David Kiguel, P. Eng.,Hydro One Networks, Inc.
Michael Bilheimer, The United Illuminating Company

Sector 2 – Reliability Coordinators

Calvin Duncan, P. Eng., New Brunswick System Operator
Gregory Campoli, New York Independent System Operator
Richard Burke, ISO New England, Inc.
Joseph Fox, ing., Hydro-Québec TransÉnergie
Esther Kim, Independent Electricity System Operator

ALTERNATES

Scott Berry, Independent Electricity System Operator (Alternate #1)
Tina Teng, Independent Electricity System Operator (Alternate #2)
Matthew Goldberg, ISO New England, Inc.

Sector 3 – Transmission Dependent Utilities, Distribution Companies, and Load-Serving Entities

Vicki M. O'Leary, National Grid
Ben Wu, Orange and Rockland Utilities, Inc.

ALTERNATES

Michael Jones, National Grid

Sector 4 – Generator Owners

Thomas Czerniewski, Entergy Services, Inc.
Chantel Haswell, NextEra Eneryg Resources, LLC
Mike Garton, Dominion Resources Services, Inc.

ALTERNATES

Michael Gildea, Dominion Resource Services
Brian Murphy, NextEra Energy Resources, LLC

Sector 5 – Marketers, Brokers, and Aggregators

Bruce Metruck, New York Power Authority
Brian Evans-Mongeon, Utility Services, Inc.

ALTERNATES

Wayne Sipperly, New York Power Authority

Sector 6 – State/Provincial Regulatory and/or Governmental Authorities

Randy D. Crissman, New York Power Authority

Sector 7 – Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities

To Be Determined

ALTERNATES

Saul Rojas, New York Power Authority

RELIABILITY COORDINATING COMMITTEE - 2012

Chairman	Donald L. Gates, ISO New England, Inc.
Co-Vice Chairman	Michael Schiavone, National Grid
Co-Vice Chairman	Alden Briggs, New Brunswick System Operator

Sector 1 – Transmission Owners

Randy MacDonald, New Brunswick Power Transmission Corporation
Tony O'Hara, New Brunswick Power Transmission Corporation (Alternate)
Brian Conroy, Central Maine Power Company
David Conroy, Central Maine Power Company (Alternate)
Michael Schiavone, National Grid
Robert J. Pellegrini, The United Illuminating Company
Jonathan Appelbaum, The United Illuminating Company
Paul Renaud, Vermont Electric Power Company, Inc.
Hantz A. Présumé, Vermont Electric Power Company, Inc. (Alternate)
Thomas C. Duffy, Central Hudson Gas & Electric Corporation
Michael Forte, Consolidated Edison Company of New York, Inc.
Peter Yost, Consolidated Edison Company of New York, Inc. (Alternate)
David Clarke Long Island Power Authority
Brad Bentley, Northeast Utilities
Steve DeCarlo, New York Power Authority
Michael Parisi, New York Power Authority (Alternate)
Raymond Kinney, New York State Electric & Gas Corp.
Joseph Fleury, New York State Electric & Gas Corp. (Alternate)
John Allen, Rochester Gas and Electric Corporation
Paul Casey, Nova Scotia Power Inc.
David Sanford, Nova Scotia Power Inc. (Alternate)
Paul Tremblay, Hydro One Networks, Inc.
John Sabiston, Hydro One Networks, Inc. (Alternate)

Sector 2 – Reliability Coordinators

Alden Briggs, New Brunswick System Operator
Donald L. Gates, ISO New England, Inc.
Mike Henderson, ISO New England, Inc. (Alternate)
Dana Walters, New York Independent System Operator
Barbara Constantinescu, Independent Electricity System Operator
Len Kula, Independent Electricity System Operator (Alternate)
Pierre Paquet, Hydro-Québec TransÉnergie

Sector 3 – Transmission Dependent Utilities, Distribution Companies, and Load-Serving Entities

Stéphane Dufresne, Hydro-Québec Distribution
Luc Bernier, Hydro-Québec Distribution (Alternate)
Curt Dahl, Long Island Power Authority
Steve Marron, Long Island Power Authority (Alternate)
Marilyn Brown, New York Power Authority
Andrew Stewart, New York Power Authority (Alternate)

Dwayne Basler, Northeast Utilities

Sector 4 – Generator Owners

Michael Garton, Dominion Resources Services, Inc.
Michael Gildea, Dominion Resources Services, Inc. (Alternate)
Jim Watson, Dynegy, Inc.
Dean Ellis, Dynegy Inc. (Alternate)
Thomas Czerniewski, Entergy Nuclear Northeast, Inc.
To Be Determined, NextEra Energy Resources, LLC
David Appelbaum, NextEra Energy Resources, LLC (Alternate)
Yuri Fisman, Long Island Power Authority
Edward Welz, New York Power Authority
Brad Van Auken, New York Power Authority (Alternate)
David Ramklawan, Ontario Power Generation, Inc.
William Smagula, Northeast Utilities
Drew O'Keefe, Northeast Utilities (Alternate)

Sector 5 – Marketers, Brokers, and Aggregators

Glen McCartney, Constellation Energy Commodities Group, Inc.
Louis Guilbault, Hydro-Québec Energy Services (US) Inc.
Scott Leuthauser, Hydro-Québec Energy Services (US) Inc.
Yannick Vennes, Hydro-Québec Energy Marketing, Inc.
Ben Chu, Long Island Power Authority
William Nadeau, New York Power Authority
William Palazzo, New York Power Authority (Alternate)
Bradley Weghorst, PPL Energy Plus, LLC
Mark Heimbach, PPL Energy Plus, LLC (Alternate)
Brian Evans-Mongeon, Utility Services, LLC
John Helme, Utility Services, LLC

Sector 6 – State and Provincial Regulatory and/or Governmental Authorities

TBA, New York State Department of Public Service
Edward Schrom, Jr., New York State Department of Public Service (Alternate)
Bruce Metruck, New York Power Authority
Wayne Sipperly, New York Power Authority

Sector 7 – Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities

Roger Clayton, New York State Reliability Council, LLC
George C. Loehr, New York State Reliability Council, LLC (Alternate)

PUBLIC INFORMATION COMMITTEE - 2012

Chairman	Steve Allen, Salient Point LLC
Members:	
New England:	Ellen Foley, ISO New England, Inc.
New York:	Michael Clendenin, Consolidated Edison Company of New York, Inc. John Cordi, New York Independent System Operator
PJM:	Ray E. Dotter, PJM Interconnection
Maritimes:	Michel Losier, NB Power Holding Corporation

Midwest ISO:	To be determined
Québec:	To be determined
Ontario:	Terry Young, Independent Electricity System Operator
ReliabilityFirst:	Larry Bugh, ReliabilityFirst Corporation
NERC:	Kimberly Mielcarek, NERC
ALTERNATES	Vera B. Geba, Salient Point LLC
	Gary Paslow, New York Independent System Operator

NPCC Committee Reports – The President and CEO informed the Board that the committee reports would be presented during the Annual Members Meeting scheduled for later that morning.

Designation of NPCC Officers

The President and CEO presented for Board approval the proposed designation of NPCC's officers for 2012. A motion to approve the designation of NPCC's officers for 2012 was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board.

NPCC OFFICERS - 2012

Edward A. Schwerdt	President and CEO
Jennifer Budd Mattiello	Vice President and COO
William G. Longhi	Vice Chairman
Bruce B. Campbell	Vice Chairman
Andrianne S. Payson, Esq.	Secretary
Andrew J. Fawbush, Esq.	Assistant Secretary
Christopher Weir, CPA	Treasurer
Robert J. DeAngelo	Assistant Treasurer

Approval of 2012 NPCC Independent Board Chair

The Board Chair left the meeting. Mr. Longhi then presented the draft Independent Consulting Agreement for NPCC's Independent Board Chair. The President and CEO informed the Board of the changes in the draft Independent Consulting Agreement, which reflected (i) a term that commences on January 1, 2012 and ends on December 31, 2013, and (ii) an increase in the retainer and the services included under the retainer for 2012-2013 to make the agreement for the Board Chair more compatible with the contracts for the NPCC independent directors for the same two-year term. One Board member inquired into the performance review process of the Board Chair for 2011. Several Board members provided their individual assessment of the Board Chair's performance during the past year and Ms. Payson provided summary results of the Board self-assessment questionnaire on this specific item. The Board recommended that going forward the CGNC should provide it with the results of the annual Board self-assessment questionnaire on the performance of the Board Chair for that year and a written summary of the Board Chair's performance for the past year, prior to presenting the Board with the draft Independent Consulting Agreement for the Board Chair. The Board additionally recommended that the CGNC conduct an annual assessment of the performance of the Independent Directors. Following further discussion, a motion to retain Mr. Reed as Chairman of the NPCC Board of Directors for 2012-2013 and to approve the Independent Consulting Agreement as presented was duly made, seconded, and unanimously approved by the Directors in each active Sector of the Board. The Board Chair then returned to the Board meeting.

Organizational Matters

MDCC Recommendations – The President informed the Board that after discussions with the MDCC, he was recommending to the Board a merit salary increase of 3% effective January 1, 2012 for NPCC Staff, which reflects their significant efforts and achievements this past year. He explained that the proposed 3% increase was consistent with the NPCC budget and with merit salary increases that other Regional Entities had approved for their staff. Mr. Longhi added that based on the research conducted and Regional surveys reviewed by the MDCC, the committee believed that a proposed merit package increase of 3% was consistent with merit package increases approved by other organizations in the industry. The Board Chair noted that the MDCC had endorsed the proposed 3% merit increase and presented draft resolutions for Board review and approval. A motion to approve the MDCC's recommendation of a 3% merit salary increase for NPCC Staff in 2012 was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board with one abstention. Following the vote, the Board briefly discussed the publication of NPCC Board minutes on the Members only section of NPCC's website.

The President and CEO and the Vice President and COO then left the meeting. Mr. Fawbush then joined the meeting via teleconference.

The Board Chair distributed draft Board resolutions with the MDCC's recommendation for the President and CEO's salary increase for 2012. He then provided the Board with an update of recent MDCC activities in connection with the annual performance review of the President and CEO. He explained to the Board that the MDCC met previously to discuss the performance of the President and CEO during 2011 and to review comparable salaries paid to other Regional Entity Presidents. He noted that on behalf of the MDCC, he had conducted a "360 review" by which he had interviewed the "direct reports" of the President and CEO, as well as Board members, other Regional Entity Presidents and NERC Staff members regarding the performance of the President and CEO during 2011. The Board Chair provided a summary of the feedback he received regarding the President and CEO's performance in 2011 and informed the Board that an independent compensation consultant would be retained in 2012 to conduct a compensation review for the President and CEO position as well as the positions held by other senior staff. The Board noted that the MDCC would oversee the work performed by the compensation consultant and requested that the MDCC provide regular updates to the Board of the work performed by the compensation consultant. Several Board members expressed their views regarding the appropriate level of compensation that should be paid to the NPCC President and CEO for 2012, taking into account the salaries paid to other Regional Entity Presidents in a competitive market, NPCC's status as a "quasi-public" not-for-profit corporation in the State of New York, and that the "economy is shrinking" as reflected by the austerity measures implemented by many states. Following discussion, a motion to approve the MDCC's recommendation of an increase in the base salary of the President and CEO was duly made, seconded and approved by the Directors in each active Sector of the Board with one abstention.

Mr. Fawbush left the meeting. The President and CEO and the Vice President and COO then returned to the meeting.

Topics for 2012 Board Strategy Session – The Board Chair informed the Board that he had prepared a list of topics for the upcoming 2012 Board Strategy Session, which included the following: (i) the industry perception of NPCC compared to other Regions and NPCC's steps to reach the "next level" as a Regional Entity; (ii) Board policy positions, particularly if they conflict with positions taken by NPCC members; (iii) the format for written reports submitted by Board committees; (iv) balancing the President and CEO function and the role of the Board; and (v) Board policy or strategic issues for input into the "NERC One Enterprise Planning Process." Board members spent a fair amount of time discussing the perception of NPCC among the other Regional Entities, the relationship between regulators and the industry, and the

influence of politics on the relationship between the two groups. The Board agreed to resume thediscussion of these items during the 2012 Board Strategy Session. The President and CEO asked Board members to submit additional topics for the 2012 Board Strategy Session.

Administrative Matters

Board Self-Assessment – The Board Chair reminded Board members to submit their responses to the NPCC Board 2011 self-assessment matrix. He noted that the results of the Board self-assessment would be discussed in detail during the Board's Strategy Session on January 31, 2012.

Other Matters

FERC Approval of NPCC as WECC Compliance Enforcement Authority – The Board noted the FERC letter dated November 15, 2011 approving NERC's petition for NPCC to serve as the Compliance Enforcement Authority for WECC-registered functions in the United States portion of the WECC Region. The FERC letter was previously circulated in the Board agenda package prior to the Board meeting.

Approval of NPCC Regional Standard PRC-006-NPCC-01 – Mr. Guy Zito, NPCC's Assistant Vice President – Standards, joined the meeting to present the RSC's second proposed Regional Reliability Standard, *Automatic Underfrequency Load Shedding*, for Board consideration and approval. Mr. Zito explained that the RSC started working on the proposed standard in July 2009, and had just completed its third draft, which was posted for comment on the NPCC website on May 6, 2011. He noted that the process to develop the proposed standard included two meetings with NERC, two NERC quality reviews, a presentation to the industry at a Compliance workshop, the development of a Cost Effective Analysis Procedure (CEAP) at the Board's request, and application of the CEAP to the proposed standard to assess its cost impact. He further noted that CEAP was also presented at the North American Generator Forum in Atlanta on October 11, 2011. Mr. Zito informed the Board that there was a completed ballot on November 18, 2011 with an 83% affirmative vote approving the draft regional standard. He explained that Hydro-Québec recently identified a minor correction to the proposed standard, and had requested Board approval of the correction as a non-substantive change to the proposed standard. The Board noted that the error appeared on page 29 of the proposed standard in UFLS Table 4: Québec Interconnection, and that the asterisk in Table 4 should read "Load must be fixed at all times *when above 60% of the peak load*." In response to questions from the Board, Mr. Zito noted the following: (i) he believed that the 2-1/2 years it took to develop the proposed standard would not be the typical timeframe to develop a Regional Standard; and (ii) the CEAP for the proposed standard had an estimated cost of $8 million for the UFLS program change and implementation, which reflects only the capital costs) submitted by the Members who responded to the survey. Mr. Zito explained the $8 million estimate did not reflect the total potential costs of implementation within the NPCC Region by all Members, or include any ongoing maintenance costs. One Board member noted that there was no calculation of the "benefits" that would be realized by the proposed standard and questioned whether the RSC attempted to quantify benefits as part of a cost-benefits analysis for the proposed standard. The Board was informed that, in this instance, the CEAP was applied to a standard already under development and that the reliability need had been identified as a 2003 Blackout recommendation. The Board questioned the feasibility of quantifying the benefits of the proposed standard, but noted that NPCC's work in the reliability area since the 1965 Black-out could attest to the "benefits" realized to date. Following further Board discussion, Mr. Zito agreed to complete a "benefits" assessment as part of CEAP going forward. The Board agreed to continue the cost-benefits analysis discussion during the 2012 Board Strategy Session. A motion to approve the draft *Automatic Underfrequency Load Shedding* Regional Standard PRC-006-NPCC-01 was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Adjournment

There being no further business, the Board Chair adjourned the meeting of the NPCC Board of Directors at 10:20 a.m.

Approved by Board action on _____, 2012.

Submitted by,

_____
Andrianne S. Payson
NPCC Secretary

EXHIBIT C
LIST OF ATTENDEES
November 30, 2011

Present:	Harvey J. Reed, Chairman Edward A. Schwerdt, President and CEO Jennifer Budd Mattiello, Vice President and COO Andrianne S. Payson, Esq., Secretary Andrew J. Fawbush, Esq., Assistant Secretary
	And the following members of the Board of Directors:
Sector 1 (TOs)	William G. Longhi, Orange and Rockland Utilities, Inc. André Boulanger, Hydro-Québec TransÉnergie
Sector 2 (RCs)	Peter Brandien, ISO New England, Inc. Bruce B. Campbell, Independent Electricity System Operator Rick Gonzales, New York Independent System Operator, Inc. (via teleconference)
Sector 3 (TDUs, DCs, LSEs)	David H. Boguslawski, Northeast Utilities Michael Penstone, Hydro One
Sector 4 (GOs)	Andrew Barrett, Ontario Power Generation, Inc.
Sector 5 (Marketers, Brokers and Aggregators)	Glen McCartney, Constellation Energy Commodities Group, Inc. Matthew J. Picardi, Shell Energy NA (by proxy to the President) Daniel Whyte, Brookfield Power Generation
Sector 6 (Customers)	–
Sector 7 (Regulatory)	Hans Mertens, Vermont Department of Public Service Tammy Mitchell, NYS Department of Public Service (via teleconference)
Sector 8 (Others)	Michael Forte, New York State Reliability Council, LLC
Guests	Guy Zito, NPCC Assistant Vice President, Reliability Standards

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COMMITTEE MEMBERSHIP CHANGES

Reliability Coordinating Committee (RCC)

Sector (3) – Transmission Dependent Utilities ("TDUs"), Distribution Companies and Load, -Serving Utilities ("LSE")

Ms. Anie Philip as Long Island Power Authority alternate, replacing Mr. Steve Marron.

Regional Standards Committee (RSC)

Sector (5), Marketers, Brokers and Aggregators

Mr. Brian Robinson as Utility Services, Inc. member, replacing Mr. Brian Evans-Mongeon.

Mr. Brian Evans-Mongeon as Utility Services, Inc. alternate.

Compliance Committee (CC)

Sector (5), Marketers, Brokers and Aggregators

Ms. Jill Loewer as Utility Services, Inc. member, replacing Brian Evans-Mongeon.

Mr. Brian Evans-Mongeon as Utility Services, Inc. alternate.

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Scope of Work
for the
Regional Standards Committee (RSC)

The NPCC Regional Standards Committee (RSC), a committee of the NPCC Board of Directors (BOD), is charged with:

1. managing the NPCC Regional Standards Development Process.
2. managing the NPCC Directory and Criteria Development Process.
3. providing consolidated NPCC Regional review and comment to the existing and proposed NERC Standards and Variances as well as participating in the NERC Reliability Standards Development Process.
4. reviewing the FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) related to reliability Standards, providing a forum for developing consensus viewpoints, and submitting comments to FERC, as necessary.
5. reviewing NERC Compliance Application Notices (CANs) working in coordination with the NPCC Compliance Committee (CC) and submitting comments to NERC, as necessary.
6. providing consolidated NPCC Regional review and comment to the existing and proposed NERC Standards Development Process Manual, and to the NERC Rules of Procedure as they relate to Standards Development.
7. determining the need for and coordinating the development and application for interpretations.
8. providing a forum for sharing viewpoints and opinions with the goal of achieving consensus.
9. conducting the NPCC Cost Effective Analysis Procedure "CEAP" for developing regional standards and produce the associated reports

The RSC or RSC Executive Committee will solicit input from NPCC groups and for all submissions of standards related comments on behalf of NPCC in accordance with the RSC Triage process. The RSC will be the only group submitting comments to FERC, NERC, or any other industry entities on behalf of the NPCC Region.

The RSC is an open and balanced stakeholder committee inclusive of all industry stakeholder interests that provide for or are materially impacted by the reliability of the bulk power system.

The RSC meetings will be open to all stakeholders who want to participate and 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 NPCC Standards Staff which will administer the NPCC Regional Standards Process(es) and coordinate the review and submission of comments.

The RSC will be chaired by an NPCC member of Staff who will be assisted by the NPCC Regional Standards Process Manager (also a member of NPCC Staff) along with co-vice chairs elected by the RSC from the existing members of the Committee at the time the vote is taken. 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 in accordance with the NPCC Amended and Restated Bylaws.

Members of the RSC will be elected by the NPCC Board. Each of the NPCC Sectors, as defined in the NPCC Amended and Restated Bylaws, will be represented on the RSC.

Subcommittees and ad hoc Working Groups will be formed upon request of the RSC, by NPCC Standards program area Staff and all associated scopes or charters developed will be approved by the RSC in accordance with the most recent approved NPCC Amended and Restated Bylaws.

A. Management of the NPCC Regional Standards Process

The RSC is responsible for managing the standards process for development of standards, VRFs, VSLs, definitions, variances and interpretations in accordance with the NPCC Regional Reliability Standard Process Manual, NERC and FERC documentation. The RSC is responsible for ensuring the quality of all Standards related materials.

The RSC is responsible for administering the Cost Effectiveness Analysis Procedure "CEAP" to determine if a proposed Regional Standard is cost effective, on a requirement by requirement basis in achieving its reliability objective(s).

The RSC will be available to advise the NPCC BOD on any and all standards related matters.

All RSC Regional Standard related decision making activities will be approved or rejected by a vote as outlined in the NPCC Amended and Restated Bylaws as they pertain to quorum and voting rules.

B. Management of the NPCC Directory and Criteria Process

The RSC manages and has oversight of the processes for development of NPCC Directories and Criteria. The RSC is responsible for ensuring the quality of all Directory and Criteria related materials. RSC will provide groups generating documents Quality Review guidance, and guidance on how to generate the documents and administer the NPCC Directory Development Procedure.

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

C. NERC Reliability Standards

The RSC will:

- Provide NPCC review and coordinate the submission of NPCC comments to existing and developing NERC Reliability Standards when posted for NERC "Open Process Review."
- Provide a forum for NPCC to participate, solicit, and provide Regional comments as new Standard Authorization Requests (SARs), and their respective Reliability Standards, are developed in accordance with the NERC Standard Processes Manual.
- Identify upcoming issues associated with new NERC Reliability Standards and their potential impact on the NPCC Region, (i.e. Regional Difference).
- Propose solutions or guide the development of the Standards through effective and timely comments and soliciting NPCC participation on the SAR and Reliability Standards drafting teams.
- Develop and maintain a Web-Based Database for tracking and scheduling Standards development activities from a Regional perspective.
- Target a wider range of participants in the standard commenting process. Develop databases and e-mail list servers to engage more members and to elicit different perspectives.
- Conduct the process for notification, solicitation, commenting on and for proposing revisions to Standards using the NPCC Triage Process.
- Follow up on proposed and adopted changes to the NERC Standard Processes Manual and Rules of Procedure, as they apply to Reliability Standards, and provide NPCC members with basic information (or pointers to the NERC Website) for a common understanding of the process.
- Coordinate the activities of NPCC members on standard drafting teams and ensure sufficient regional participation on such teams.
- The RSC will review draft NERC CANs for Reliability Standard and compliance implications after receiving CC input, and submit comments to NERC.

D. FERC Activities Affecting Standards

The RSC will review FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) relating to Reliability Standards. The RSC will discuss, develop comments, and if necessary submit the comments to FERC on behalf of NPCC.

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January 18, 2012

To: NPCC Board of Directors

From: Stanley E. Kopman
Assistant Vice President, Compliance Registration and Enforcement

Subject: Draft Revised Scope of the NPCC Compliance Committee

Dear Members:

Attached please find, for your review and approval, the draft revised scope of the NPCC Compliance Committee. This draft was endorsed by the NPCC Compliance Committee on January 11, 2012.

Sincerely,

Stanley E. Kopman
Assistant Vice President, Compliance Registration and Enforcement
NPCC, Inc.

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Scope of Work
For
NPCC Compliance Committee (CC)

Committee Mission

The NPCC Compliance Committee (CC) shall be charged with providing objective stakeholder policy input to the NPCC Compliance Monitoring and Enforcement Program (CMEP) and the NPCC Criteria Compliance Enforcement Program (CCEP).

The NPCC CMEP encompasses compliance monitoring, assessment, and enforcement of NERC Reliability Standards and NPCC Regional Reliability Standards. The NPCC CCEP encompasses compliance monitoring, assessment, and enforcement of the NPCC Reliability Criteria. The CC shall provide an oversight role of the NPCC Compliance Staff's implementation of the CMEP. In this oversight role, the CC will review and endorse the processes used by the NPCC Compliance Staff to implement the CMEP. The CC shall be responsible for final approval of compliance assessments related to the CCEP, which includes non-monetary sanction recommendations.

Committee Functions

The CC is charged with the following responsibilities related to the CMEP:

1. Review and approve NPCC Compliance Procedures for implementing the CMEP.
2. Conduct annual evaluation of the NPCC Compliance Staff's implementation of the NPCC CMEP.
3. Review and endorse the processes used by NPCC Compliance Staff for noncompliance assessments and determination of sanctions consistent with the ERO Sanctions Guidelines related to NERC and NPCC Regional Reliability Standards.
4. Provide final approval of compliance assessments related to the NPCC CCEP to the Reliability Coordinating Committee (RCC).
5. Forward any identified violations of CCEP criteria and recommended sanctions to the NPCC Enforcement Panel for processing.
6. Review and endorse annual NPCC CMEP Implementation Plan as presented by NPCC Compliance Staff.
7. Review and endorse any proposed modifications or revisions to the NPCC CMEP as presented by NPCC Compliance Staff or NERC.
8. Impanel the Hearing Body to resolve contested compliance and/or sanction and penalty determinations related to the CMEP in accordance with the NPCC Bylaws. Oversee activities of any subcommittees, working groups, or users groups that are formed.
9. Provide regular reports to the NPCC Board of Directors on all matters related to the NPCC CMEP.

Committee Structure

The Committee will consist of representatives from the seven voting sectors as described in the Amended and Restated Bylaws of Northeast Power Coordinating Council, Inc.("NPCC").

The Committee will be chaired by the Assistant Vice President of Compliance and Registration or his /her designee. The Committee will elect a vice chair from its members.

The Committee will be bound by the same quorum and voting rules applicable to the NPCC Board of Directors and described in the Amended and Restated Bylaws of Northeast Power Coordinating Council, Inc. ("NPCC") while conducting CC business.

The Hearing Body will consist of an independent Hearing Officer and the two (2) Independent Directors of the NPCC Board. In order to impanel the Hearing Body, the CC chair will notify the two (2) Independent Directors of a hearing request and the CC will select the independent Hearing Officer. The Hearing Body will utilize a simple majority vote to resolve issues. This voting rule, along with the structure of the Hearing Body, fully supports the requirement that no two stakeholder sectors may control, and no single stakeholder may veto, a matter before the Hearing Body.

DRAFT

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Date: January 18, 2012

To: NPCC Board of Directors

From: Guy V. Zito
Assistant Vice President – Standards
Chair, Regional Standards Committee

Subject: Regional Standards Committee (RSC) Transmittal to the NPCC BOD, 2012-2013 RSC Work Plan

The NPCC RSC respectfully submits the attached 2012-2013 draft RSC Work Plan for BOD consideration and approval. The RSC Work Plan is responsive to the NERC 2012-2014 NERC Reliability Standards Development Plan that outlines the ERO's schedules and activities as they are related to the individual Standards Projects and also the directives issued to NPCC regarding the development of Regional Standards and comports with the NERC "One Enterprise" model. The Work Plan will also be consistent with the 2012 and 2013 NPCC Business Plan and Budgets currently under development.

The Work Plan contains activities which support NERC's Results Based initiative, and reflect NPCC's continued commitment to support NERC's standards development activities. The Work Plan also includes support of compliance related matters which affect standards' requirements and the development or revision of standards.

The Work Plan also reflects the significant amount of work that has the RSC has assumed due to NERC's issuances of requests for interpretations, and Compliance Application Notices (CANs). The NPCC RSC is devoting the time necessary to properly review and evaluate these, as well as all other relevant NERC and FERC items related to standards which require review and comment.

cc: Regional Standards Committee

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Northeast Power Coordinating Council, Inc.
Regional Standards Committee
Work Plan for Calendar Years 2012-2013

The following Regional Standards Committee (RSC) activities planned for 2012 -2013 will be consistent with the NPCC 2012 and 2013 Business Plans and Budgets, Organizational Goals, and also will continue to be supportive of the Results Based Standards efforts currently underway. Also, the plan will be responsive to the new NERC Reliability Standards Development Process, containing expedited schedules with rapid and successive revision and ballot provisions.

Core Reliability Standards Functions

- Review, promote, and support the Results Based Standards initiative and continuation of standards developmental work going on within NERC.
- Promulgate the Results Based Standards initiative throughout the Northeast.
- Refine, finalize, and implement Cost Effective Analysis Procedure and apply to NPCC regional standards development. Promote NERC consideration and adoption of NPCC Cost Effective Analysis Procedure.
- Develop and/or utilize NERC tools to incorporate the "Results Based" types of requirements into the NPCC Regional Standards under development.
- Review and participate in the Regional Standards development process, and develop NPCC Regional Reliability Standards on a schedule as directed by NERC and the reliability related needs of the Region.
- Coordinate NPCC Regional Standards development with the development of standards appearing in the NERC reliability standards development plan.
- Coordinate the NPCC participation in the review and the revision of the CIP standards per Order 706.
- Monitor and coordinate NERC's CEO top reliability related issues and priorities.
- Coordinate the NPCC participation in the review and the revision of NERC Standards per Order 693 addressing Directives from the Commission and any Provincial Regulatory directives.
- Review and revise the Regional Reliability Standards Development Procedure for filing with the FERC as may be necessary to promote consistency and support the ERO One Enterprise model.
- Manage the Regional Reliability Standards development processes.
- Manage the development and revision of the Regional Reliability Directories
- Continue to assist the NPCC Compliance Committee by developing Phase 2 of the Directory Project involving revision of criteria language into requirements that are measureable and conducive to compliance assessments.
- Coordinate and provide input to the development and prioritization of ERO reliability standards within NERC reliability standards work plan.
- Conduct thorough reviews of all NERC standards being developed or revised and coordinate comments for Northeastern North America utilizing the NPCC Triage Process as necessary to ensure timely reviews.
- Ensure the NERC standards have measurable "Results Based" requirements.
- Develop and submit Standard Authorization Requests for revisions when necessary to improve and address reliability related issues for approved or draft standards.

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Regional Standards Committee
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- Develop comments and ballot recommendations or "issues statements" for all NERC standards under development.
- Review and develop ballot recommendations for all NERC Formal Interpretations to standards.
- Review posted Compliance Application Notices "CANs" and coordinate NPCC Member comments and submissions.
- Participate in NERC and NPCC Quality Reviews of standards on a schedule as determined by NERC, NPCC and government regulatory authorities.
- Provide guidance for NPCC regional standard drafting teams in critical areas of Results Based Standards, Violation Severity Level, and Violation Risk Factor development as well as in ensuring quality.
- Review and monitor the NERC definition of Bulk Electric System with respect to existing standards and the impact on the northeast with assistance from the NPCC Task Forces to determine if any Regional Differences need to be initiated or revisions to Regional Standards.
- Review of North American Energy Standards Board (NAESB) postings and activities for potential conflicts with reliability related issues and objectives.
- Review FERC Orders and Provincial rulings pertaining to standards and standards development activities to ensure directives are addressed.
- Participate in the regional standards development activities and processes in other regions within the Eastern Interconnection.
- Participate in the proceedings of various NERC groups to contribute to the continual improvement to NERC standards and processes. These groups include but are not limited to:
    - NERC Standards Committee
    - NERC Standards Committee Process Subcommittee
    - NERC Standards Committee Communications Subcommittee
    - NERC Functional Model Working Group
    - NERC Regional Standards Group
    - NERC SAR and Standards Drafting Teams

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NERC ERO Reliability Standards Activities

The following Standards are scheduled for revision and or development in the latest draft of the "NERC Reliability Standards Development Plan: 2012 – 2014", and include the following Standards Projects. NERC has recently undertaken a prioritization of the projects into three classes; Reliability, Time Sensitivity, and Practicality and the below list is subject to change. Also note that some standards appear in more than one project due to potential retirement issues and potential division of requirements of that standard into multiple other standards and projects.

Standards Projects Scheduled for 2012-2014 development activity include a total of 36 Projects of Continent-wide Standards Development:

- **2006-06 Reliability Coordination. This project ranked #13 in Reliability Priority.**
- **2007-02 Operating Personnel Communication Protocols. This project ranked #5 in Reliability Priority.**
- **2007-03 Real-time Transmission Operations. This project ranked #4 in Practicality Priority.**
- **2007-06 Protection System Coordination. This project ranked #4 in Reliability Priority.**
- **2007-07 Vegetation Management.**
- **2007-09 Generator Verification.**
- **2007-12 Frequency Response. This project ranked #10 in Reliability Priority, and was tied for #2 in Time Sensitivity Priority.**
- **2007-17 Protection System Maintenance and Testing. This project ranked #3 in Reliability Priority.**
- **2008-06 Cyber Security - Order 706. This project ranked #1 in Reliability Priority.**
- **2009-01 Disturbance and Sabotage Reporting. This project ranked #7 in Reliability Priority.**
- **2010-05.1 Phase 1 of Protection Systems: Misoperations. This project ranked #8 in Reliability Priority.**
- **2010-07 Generator Requirements at the Transmission Interface. This project ranked #13 in Practicality Priority, and was tied for #2 in Time Sensitivity Priority.**
- **2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves.**

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This project ranked #1 in Time Sensitivity Priority, and #2 in Practicality Priority.

- **2010-17 Definition of Bulk Electric System. This project ranked #10 in Reliability Priority, and was tied for #2 in Time Sensitivity Priority.**
- **2008-02 Undervoltage Load Shedding. This project ranked #14 in Reliability Priority, and will be started upon the completion of 2006-06 Reliability Coordination.**
- **2009-02 Real-time Monitoring and Analysis Capabilities. This project ranked #1 in Practicality Priority, and will be started upon the completion of 2007-03 Real-time Transmission Operations.**
- **2009-03 Emergency Operations. This project ranked #3 in Practicality Priority, and will be started upon the completion of 2008-06 Cyber Security – Order 706.**
- **2010-01 Support Personnel Training. This project ranked #15 in Reliability Priority, and will be started upon the completion of 2009-01 Disturbance and Sabotage Reporting.**
- **2010-05.2 Phase 2 of Protection Systems: SPS and RAS. This project ranked #11 in Reliability Priority, and will be started upon the completion of the first phase of the project, 2010-05.1 Phase 1 of Protection Systems: Misoperations.**
- **2010-13.2 Phase 2 of Relay Loadability: Generation. This project has been identified as having a higher priority, as it has a FERC deadline. While this was accounted for in the Prioritization, the SC agreed that this should take precedence over the 5-year review projects considered in the Prioritization. This project will be started upon the completion of 2007-12 Frequency Response.**
- **2012-04 Protection System Commissioning Testing. This project ranked #9 in Reliability Priority, and will be started upon the completion of 2007-17 Protection System Maintenance and Testing**
- **2007-11 Disturbance Monitoring. This project will start upon completion of 2010-17 Definition of Bulk Electric System.**
- **2008-01 Voltage and Reactive Panning and Control. This project ranked #6 in practicality, and will start upon completion of 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves**
- **2008-12 Coordinate Interchange Standards. This project will start upon completion of 2010-07 Generator Requirements at the Transmission Interface.**
- **2009-07 Reliability of Protection Systems. This project ranked #2 in Reliability Priority, and will start upon completion of 2007-06 Protection System**

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Coordination.

- **2010-14.2 Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent. This project will start upon completion of 2009-02 Real-time Monitoring and Analysis Capabilities.**
- **2012-01 Equipment Monitoring and Diagnostic Devices. This project will start upon completion of 2007-02 Operating Personnel Communication Protocols.**
- **2012-06 Generator Capabilities, This project ranked #6 in Reliability Priority, and will start upon completion of both 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves and 2007-09 Generator Verification.**
- **2009-04 Phasor Measurements. This project will start upon completion of 2009-03 Emergency Operations.**
- **2009-05 Resource Adequacy Assessments. This project will start upon completion of 2012-04 Protection System Commissioning Testing.**
- **2010-03 Modeling Data. This project will start upon completion of 2008-01 Voltage and Reactive Panning and Control.**
- **2010-04 Demand Data. This project will start upon completion of 2010-05.2 Phase 2 of Protection Systems: SPS and RAS.**
- **2010-08 Functional Glossary Model Revisions. This project will start upon completion of 2010-01 Support Personnel Training.**
- **2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings. This project will start upon completion of the second phase of this project, 2010-13.2 Phase 2 of Relay Loadability: Generation.**
- **2010-16 Definition of System Operator. This project will start upon completion of 2012-04 Protection System Commissioning Testing.**
- **2012-05 ATC Revisions - Order 729. This project will start upon completion of 2008-12 Coordinate Interchange Standards.**

In addition there are another 12 projects in the latest draft of the NERC Reliability Standards Development Plan scheduled to start beyond 2013, some of which have not been prioritized and may affect the list above. The total number of standards projects currently listed in NERC's is 48.

Additional Priority Projects (near completion):

- **Project 2006-08 Transmission Loading Relief**

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- **Project 2007-04 Certifying System Operators**
- **Project 2010-17 Definition of Bulk Electric System and conforming changes to NERC Rules of Procedure**
- **PRC-002-NPCC NPCC UFLS Regional Standard**

NERC will also continue to coordinate standards development activities with the business practices developed by the North American Energy Standards Board (NAESB).

NPCC Regional Standard and Directory Activities and Requirements

- Develop the following regional standards and requirements utilizing the NPCC Regional Reliability Standards Development Procedure if necessary and directed by the ERO or as needed in response to the revision of the ERO standard(s);

    - Special Protection Systems Standard
    - Regional Reserve Sharing Groups Standard

- NPCC regional Underfrequency Load Shedding Standard, complete development and once approved, compile historical documentation and submit to NERC BOT for approval
- Develop any required responses to regulatory inquiry for NPCC Regional Disturbance Monitoring Standard and provide to FERC and the applicable Provincial regulatory authorities for their information or approvals, as may be required, i.e. data requests, filings to address directives etc.
- Develop the necessary regional standard filings with the FERC and applicable Provincial regulatory authorities for the NPCC Underfrequency Load Shedding Standard
- Address any outstanding issues with the regulatory authorities in the US and all applicable Provincial authorities for regional standards or NPCC Directories
- Draft Regional Standards Authorization Requests, RSARs
- Produce initial drafts of regional standards for Drafting Teams to start with
- Develop proposed standards utilizing regional technical committees as assigned by the NPCC RCC.
- Work with the NPCC CC to develop the necessary compliance elements of the standards, i.e. Violation Severity Levels
- Coordinate Directory criteria requirements with Regional Standards requirements to ensure no inconsistencies exist and identify potential areas for improvement
- Develop filing for the Directories for New York State Public Service Commission to fulfill obligations for the “Carve-out” outlined in Order 672 of mandatory adherence to more stringent regional criteria for NY State
- Develop filings of Directories as required with the Provincial regulators per the various Memorandums of Understanding

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RSC Ongoing Activities

- Implement technical aspects related to the implementation of the Energy Policy Act of 2005, focusing on Standards/Criteria Development, and related FERC and ERO requirements.
- Implement the NPCC CEAP and apply initially to the developing regional standards and investigate application to the draft ERO continent wide standards.
- Review the Standards Authorization Requests, Standards, and Interpretations and provide comments as well as participate in the NERC process.
- Implement the NPCC Triage Process and ensure that the appropriate NPCC Task Forces review NERC issuances, and provide input to support a consensus opinion.
- Solicit technically qualified candidates from Northeastern North America to participate on each of the NERC drafting teams and additional members to the regional drafting teams and ensure sufficient regional representation exists on the drafting teams.
- Review FERC rulings and communicate the rulings to the NPCC members and coordinate issues for the Members.
- Participate in ballots for ERO standards and provide recommended comments and ballot positions to the NPCC Members of the NERC Registered Ballot Body.
- Review and develop comments on FERC Notice of Proposed Rulemaking (NOPR) for any and all standards-related issues as appropriate.
- Use the NPCC Triage Process to evaluate proposed standards utilizing regional technical committees, task forces and working groups.
- Educate and notify stakeholders and regulators about issues related to standards development.
- Provide a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC) and NPCC Task Force on Infrastructure Security and Technology (TFIST).
- Achieve NPCC reliability goals and objectives by initiating and efficiently completing standards development activities.
- Leverage internet and web based tool functionality to ensure interregional consistency, uniformity, and quality of regional reliability standards.
- Establish long-term strategy for standards improvement and initiate implementation.
- Ensure the topics addressed by the reliability standards parallel changing industry needs.
- Business Practices Interface
    - Coordinate the review of standards with NPCC members of the North American Energy Standards Board, details above.
    - Identify potential market issues for Regional Standards through NPCC Reliability Coordinating Committee (RCC) reviews.
- Process Improvement
    - Identify efficiencies for a coordinated NERC standards development process and NPCC Regional Standards Development Procedure and recommend revisions as applicable.
    - Participate in the revision and redrafting of the NERC rules and procedures related to standards development such as, but not limited to:

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- The NERC Functional Model Working Group
- The NERC Regional Standards Group
- The NERC Standards Committee
- The NERC Standards Committee Process Subcommittee

  - Establish goals/targets for NERC and NPCC standards procedure improvement.
- Streamline and improve the regional standards process and continue to enhance program tools.
- Communications
  - Automate notifications process to assure awareness of dates and proceedings of all standard development activities.
  - Strengthen the relationship with the industry's technical committees to ensure adequate input to standards development.
  - Sponsor NPCC Workshops and participate in NERC/ERO workshops to promote awareness and educate the industry of standards-related activities.
  - Promote the reliability objectives of the NERC standards as appropriate to the NPCC members of the NERC Registered Ballot Body.
  - Educate and inform industry stakeholders through web based tools such as "Webinars" and participation in NERC Reliability Standards Workshops, as necessary.
  - Update and inform governmental regulators and/or authorities on the standards development work plan and processes through individual project discussions and annual meetings/conferences.
  - Develop standards program communications that support NERC's overall communications platform.
  - Develop and maintain NPCC Reliability Directories that will enable users, owners and operators of the international bulk power system in the Region the ability to apply reliability requirements in NERC and NPCC as well as the more stringent NPCC regionally-specific criteria.
  - Identify future regional standard opportunities by developing a set of Regional Reliability Directories incorporating the ERO Reliability Standards, Regional Standards and regionally-specific more stringent Criteria.
  - Accomplish all directives of ERO and governmental and/or regulatory authorities with regard to regional standards development and procedures.
  - Adhere to and surpass the ERO work plan milestones, when practical, as they pertain to targets for the regional standards.

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Date: January 18, 2012

To: NPCC Board of Directors

From: Guy V. Zito
Assistant Vice President – Standards
Chair, Regional Standards Committee

Subject: Regional Standards Committee (RSC) Status Report to the NPCC Board of Directors

Since the last NPCC BOD Meeting Report, RSC activities have included, but not been limited to, the following:

- NPCC Directory development:
  - NPCC Directory #1 Phase II, Design and Operation of the Bulk Power System was developed and presented to the TFCO. CP11 working group is revising the Directory to facilitate the NPCC Criteria Compliance Enforcement Program (CCEP)
  - NPCC Directory #5 Phase II, Operating Reserve remains under development with TFCO.
  - NPCC Directories #9 and #10 Phase II, pertaining to generator capability verification were completed and balloted and approved by the NPCC Full Members.
  - A new Directory on Regional Reserve Sharing has been assigned by the RCC to TFCO. A first draft has been developed and is under review with the TFCO for refinement and development. This directory will be the basis for the standard on reserve sharing that the ERO directed NPCC to develop. CO1 is conducting a review of the reliability impact of reserve sharing.
  - RSC has also completed and approved the NPCC Directory Development Procedure which codifies how to develop, revise and maintain NPCC's Directories.
  - RSC has also completed a new and revised NPCC Glossary document. The Glossary highlights inconsistencies between NERC and NPCC terms to facilitate consistency and reduce duplicity between ERO and Regional definitions.

- The RSC through NPCC staff is preparing materials for recent stakeholder and BOD approved NPCC UFLS standard (PRC-006-NPCC-01) to file with the FERC. In addition

the standard has received NERC staff endorsement and NPCC staff, in conjunction with NERC staff, also has developed the agenda item for the February BOT meeting where the standard's approval will be sought.

- RSC completed development of a Cost Effectiveness Analysis Procedure "CEAP" to evaluate new and revised standards to ensure they meet their reliability purpose and identify the costs associated with implementation. Comments on the process were received from the industry through open process postings as well as NERC staff. In addition, the new NPCC CEAP was applied to the NPCC UFLS regional standard and the results posted on the NPCC website during ballot of that standard to provide the industry with information about the costs and effectiveness of the standard. In 2012 it is envisioned that NPCC will pilot this new CEAP by applying it to a NERC continent wide standard and sharing the results with industry and the NERC Standards Committee. This could be a potential "first step" to provide the industry with information on cost and effectiveness of a new standard to achieve a reliability objective. RSC will continue to gather input from various industry groups such as, but not limited to, North American Generator Forum, North American Transmission Forum and the ISO-RTO Council as the opportunity arises.

- The NPCC Disturbance Monitoring, (DM) Regional Standard PRC-002-NPCC-01 was approved without Directive by the FERC in October 2011. Since that time the NERC BES definition has received approval and the RSC has begun reviewing issues being raised by stakeholders due to the expanded applicability of the BES revised definition. The ERO is engaged in filing the standard with the applicable Provincial governmental authorities.

- The NPCC Special Protection System Review, (SPS) Regional Standard PRC-012-NPCC-01 initial draft has been drafted. Further direction from the NERC Drafting Team will be provided before the draft moves forward.

- The NPCC RSC has also participated on, and provided input to the NERC Standards Committee and Standards Committee Process Subcommittee. Of interest to NPCC are:

    - RSC is assisting with refining the Compliance Application Notice process and providing comments to NERC. Also there is activity in the area of an Informal Guidance Process in an attempt to provide industry with guidance rather than seeking numerous interpretations.
    - Continued review of potential revisions to Version 5 of the NERC Functional Model to capture emerging issues with Demand Side Resources as they replace the reserve obligations of Balancing Authorities.
    - Education of the NPCC membership and stakeholders on attributes of the new NERC Reliability Standards Process Manual which has been approved by FERC and is being implemented as well as changes to the NERC Rules of Procedure, through outreach and a Compliance and Standards Workshop held in December of 2011.
    - RSC has implemented its "Triage Process" to address the urgency and frequency of NERC standards related activities. RSC will continue to review and revise this process to continually strive to increase efficient utilization of NPCC's resources.

- RSC assisted and continues to assist with refinement and implementation of the NERC Prioritization tool being used to evaluate and prioritize standards projects.
- RSC is working on revising the existing NERC Self Nomination process to ensure true Subject Matter Experts are populating the NERC Drafting Teams to deliver the highest quality standards possible.
- RSC has developed and posted a first draft of a revised Regional Standards Process Manual. The RSC anticipates completing a revision by the end of 2012 however NERC is currently engaged in a major standards development process overhaul which may affect and influence how NPCC develops their regional standards.

- The RSC has worked with the NERC Standards Drafting Teams, and appropriate NPCC Task Forces and Working Groups to address regional concerns and developed ballot/re-ballot recommendations or provided issue statements for the following NERC Reliability Standards, efforts and Interpretations:

  - Project 2007-03: Real-time Operations
  - Project 2007-03: Real-time Operations, non-binding poll VRFs and VSLs
  - Project 2010-07: Generator Connection Requirements at the Transmission Interface.
  - Project 2010-07: Generator Connection Requirements at the Transmission Interface, non-binding poll VRFs and VSLs
  - Project 2008-06: CIP V5
  - Project 2008-06: CIP V5 Implementation
  - Project 2008-06: CIP V5 Definitions Dec 2011
  - Project 2009-01 Disturbance And Sabotage Reporting
  - Project 2009-01 Disturbance And Sabotage Reporting non-binding poll VRFs and VSLs
  - Project 2007-12 Frequency Response Initial Ballot
  - Project 2007-12 Frequency Response Initial Ballot non-binding poll VRFs and VSLs

- Continue to monitor emerging issues such as High Impact Low Probability, Smart Grid, Renewable Resources, and CIP development.

- Reviewed and coordinated consensus NPCC comments utilizing the NPCC subject matter experts in the task forces and working groups, to the extent possible, and transmitted comments to NERC for the projects as listed on the NPCC Website- http://www.npcc.org/documents/regStandards/Comments.aspx :

- NPCC RSC continues to participate in the activities of the NERC Regional Standards Group RSG, coordinating standard development activities with the other Regions to achieve consistency, uniformity and promote reliability objectives throughout the Interconnections in North America. The group currently is engaged in scheduling of NERC's resources to evaluate regional standards and coordinating standards requirements.

- NPCC monitors NERC, NAESB regional activities by participating in bimonthly conference calls and reviews the development of any issues for any potential reliability impacts.

- NPCC is supporting the NERC Balancing Authority and Reliability Based Control Drafting Team efforts “BARC” and ensuring coordination exists between this team and the reserve sharing efforts underway in draft Directory and Standard documents at NPCC.

- NPCC RSC is also coordinating the commenting review and revision of the Version 5 of the CIP standards currently in the development stage at NERC. The standards involve addressing outstanding FERC Directives appearing in Order 706. The RSC in conjunction with TFIST developed a ballot recommendation to reject the standards and submitted suggested revisions which would enable our members and stakeholders to support the standards. NPCC is working with the standard drafting team to effectuate those changes.

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January 18, 2012

To: NPCC Board of Directors

From: Stanley E. Kopman
Assistant Vice President, Compliance Registration and Enforcement

Subject: Draft 2012-13 Work Plan of the NPCC Compliance Committee

Dear Members:

Attached please find, for your review and approval, the draft 2012-13 Work Plan of the NPCC Compliance Committee. This draft was endorsed by the NPCC Compliance Committee on January 11, 2012.

Sincerely,

Stanley E. Kopman
Assistant Vice President, Compliance Registration and Enforcement
NPCC, Inc.

NPCC, Inc.
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NPCC Compliance Committee (CC)
2012-2013 Work Plan

The 2012-2013 Compliance Committee (CC) Work Plan defines the following aspects of the Compliance Committee:

- Core Responsibilities
- On-going activities
- Scheduled additional activities for 2012
- Partial listing of 2013 projected additional activities

The CC activities planned for 2012 -2013 will be consistent with the approved NPCC 2012 Business Plan and 2012 Organizational Goals. These in turn are intended to be consistent with the 2013 NPCC Business Plan and the 2013 NPCC Organizational Goals that are under development.

Core Responsibilities

The CC is charged with core responsibilities related to the NPCC Compliance Program that includes (i) the NPCC Compliance Monitoring and Enforcement Program (CMEP) for NERC Reliability Standards and NPCC Regional Reliability Standards; and (ii) the NPCC Criteria Compliance and Enforcement Program (CCEP) for the region-specific NPCC Criteria as follows:

- Provide objective stakeholder policy input related to:
  - the CMEP in the United States
  - the CCEP
- Provide NPCC perspective to both the NERC Compliance and Certification Committee (CCC) and the ERO Compliance and Enforcement Management Group (ECEMG) for matters related to the NERC CMEP.
- Assess the performance of the NPCC Compliance Staff's implementation of the Compliance Program, including the endorsement of the processes used for non-compliance assessments and enforcement determinations.
- Approve compliance assessments and sanction recommendations related to CCEP.
- Promote the continued education of stakeholders as to their responsibilities related to the CMEP and CCEP.

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On- Going Activities

The CC will conduct the following on-going activities:

- Review and provide comments on annual NPCC CMEP Implementation Plan as presented by NPCC Compliance Registration and Enforcement and NPCC Compliance Audits and Investigation teams.
- Identify aspects of the CMEP that will comprise CC annual evaluation of the NPCC Compliance Staff's implementation of the NPCC CMEP. These evaluations will include team assessments of the Staff's implementation of specific portions of the CMEP. The assessments will focus on identifying strengths and recommendations that will enhance the Staff's implementation of the CMEP.
- Impanel the Hearing Body to resolve contested compliance and/or sanction and penalty determinations in accordance with the NPCC Bylaws.
- Review and provide comments on any proposed modifications or revisions to the CMEP as presented by NPCC Compliance Staff or NERC.
- Review and develop consensus comments on FERC Notice of Proposed Rulemaking (NOPR) for any compliance program related issues as appropriate.
- Conduct periodic reviews of the CMEP hearing process and procedures.
- Review, modify, and approve annual CCEP Implementation Plan noting any revisions from the prior year's program.
- Review technical issues related to identified potential and/or confirmed compliance violations of NPCC Criteria. These technical issues will be reviewed by the NPCC CC to provide clarifying information for CCEP implementation revisions, identifying lessons learned, and/or developing recommended changes to the CCEP implementation processes or NPCC Criteria.
- Review and provide final approval of compliance assessments related to the CCEP, including approval of non-monetary sanction recommendations.
- Review and approve NPCC Compliance Procedures developed for implementing the various aspects of the CMEP and CCEP.
- Propose, review, and approve any modifications or revisions to the CCEP.
- Provide regular reports to the NPCC Board of Directors on all matters related to the NPCC CMEP and CCEP activities.
- Review and appropriately modify the CC Work Plan on an annual basis.

Scheduled 2012 Additional Activities

During 2012 the CC is scheduled to conduct the following additional activities:

Activities related to compliance with NERC Reliability Standards or NPCC Regional Standards

- Provide input to the NERC CCC related to the development of NERC's entity assessment program.
- Conduct an assessment of the NPCC Compliance Staff implementation of the Entity Registration Process to ensure compliance with the NERC Rules of Procedure.
- Continue development of additional CMEP related performance metrics or Key Performance Indicators (KPIs) as guidelines for assessing Compliance activities.

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- Identify potential CMEP areas for improvement and increased efficiency through the use of KPI analysis and propose enhancements to the CMEP based on this analysis on an annual basis.
- Participate in the NERC CCC stakeholder meetings. A CC member (who is not an NPCC Staff member) is the NPCC Regional representative on the NERC CCC. The CC member should also participate on one of the NERC CCC subcommittees that review and recommend changes to NERC CCC programs, processes and the NERC Rules of Procedure (ROP), such as the Procedure Subcommittee (PROCS) or the Organization Registration and Certification Subcommittee (ORCS).
- Identify items for presentation at each of the two 2012 Compliance Workshops.
- Evaluate and explore the CC's role related to compliance program implementation by the Canadian provinces within the NPCC region as the MOUs for each province are approved and implemented.

Activities related to compliance with NPCC Criteria:

- Discuss and determine additional Criteria to be included in CCEP, focusing on the ultimate goal of including all more stringent and more specific NPCC Criteria in the CCEP.
- Develop and approve 2013 CCEP Implementation Plan including the 2013 schedule for compliance submittals.
- Develop, review, and endorse CCEP related performance measures.
- Identify potential areas for CCEP improvement and increased efficiency through the use of KPI analysis and propose enhancements to the CCEP based on the performance measures analysis.

Projected 2013 Additional Activities

The following is a partial list of projected additional activities to be carried out by the CC in 2013:

- Evaluate and implement a long-term strategy for reviewing and revising the NPCC CMEP and NPCC CCEP.
- Conduct evaluation of the NPCC Compliance Staff's implementation of the NPCC CCEP. The assessments will focus on identifying strengths and recommendations that will enhance the Staff's implementation of the CCEP.
- Implement enhancements to CMEP and CCEP that were identified through the analysis of Performance Measures.

Activities listed, for 2012 and 2013 have been developed based on the current planned implementation of the NPCC CMEP, and implementation of the revised NPCC CCEP. Changes to these programs, the NERC CMEP, the NERC Rules of Procedure, or the MOUs with Canadian entities 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 Work Plan will be revised in advance of the Board of Director's annual review. In that event, the revised Work Plan would be forwarded to the NPCC Board of Directors for approval.

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Date: January 18, 2012

To: NPCC Board of Directors

From: Stanley E. Kopman
Assistant Vice President – Compliance Registration and Enforcement

Sal Buffamante
Assistant Vice President – Compliance Audits and Investigations

Subject: January, 2012 CMEP and Compliance Committee Summary Report

This document provides the NPCC Board of Directors with the latest summary of key regional issues, trends, and other significant events related to the CMEP and associated Compliance Committee activities.

- **Key Issues**

  - The NPCC Staff completed its 2011 Culture of Compliance Survey Initiative. NPCC developed and distributed a total of 165 NPCC Culture of Compliance Surveys, covering all 287 NPCC registered entities. The staff evaluated 100% of the 146 survey responses received. The evaluation consisted of reviewing the material sent by each registered entity, conducting one-on-one assessment phone calls with each survey submitter, rating each registered entity, and identifying Examples of Excellence and Best Practices.

    The initiative is documented in the "Report on 2011 NPCC Culture of Compliance Survey Initiative", which is posted on the NPCC Website. The report includes a compilation of the Examples of Excellence and the Best Practices identified which present potential mechanisms or corrective action programs for registered entities to consider when reviewing or enhancing their internal compliance programs.

    A detailed presentation, on the 2011 NPCC Culture of Compliance Survey Initiative, was made at the 2011 Fall NPCC Compliance and Standards Workshop held on December 14 -16, 2011 and attended by over 200 people.

A follow-up webinar will be held in late January or early February 2012 with all NPCC registered entities to discuss the report in detail.

- NPCC is working with the other Regions and NERC in developing audit approach documents for several reliability standards. Documents completed include MOD-001, MOD-004, MOD-008, MOD-030, COM-002, FAC-003, PRC-005 and PRC-023. Each document includes sections on Audit Approach and Data Retention requirements. These documents enable all regions to employ a consistent approach to audits involving these standards.

    - More audit approach documents are being developed based on the Tier 1 Actively Monitored List of Standards.
    - NPCC gave a presentation for the above at the Fall 2011 NERC ERO Auditors' Workshop at NERC's headquarters in Atlanta. The presentation is also posted on NERC's website under the Compliance; Regional Programs; ERO Workshop tab (Item V-A).

- NPCC has developed documentation of examples of excellence in compliance documentation, posting of evidence and preparedness for audits. NPCC shared this with the other regions and all our registered entities during the fall, 2011 compliance workshop.

- To date NPCC has received 534 Technical Feasibility Exception (TFE) submittals covering over 11,000 assets. All have been accepted for Part A and 442 have had their Part B substantive assessment done and approved. All remaining Part B assessments will be completed within the one year parameter. 48 TFE's have been terminated by the entities.

- **Significant Events/Compliance Violation Investigations**

NPCC is currently operating under Phase II of the Event Analysis Process (EAP) field trial and strongly encouraging that all such events be handled under that process.

Since the start of Event Analysis Process and the subsequent two field trials, NPCC has administered approximately 50 qualifying events as described in the five (5) categories, of the NERC ERO EAP manual, which elevate in severity from Category 1(lower significance) to Category 5 (High significance).

During the time of the two EAP Field Trial periods (Phase I – starting in October of 2010 and continuing through Phase II starting in May of 2011 and still active), of the 50 events processed the majority have been of the Category 1 type with roughly 9 of them raising to the level of a Category 2 event.

Although in its current format the EAP program requires that a compliance self assessment be prepared for only category 2 and above events, NPCC has strongly encouraged that registered entities within its footprint conduct this self assessment or standards review for all qualifying events and will continue to do so.

Although voluntary, the success rate for NPCC entities complying with this has been very high with most all submitting these self assessments to NPCC. It is because of this fact that the opening of any Compliance Violation Investigations has been avoided.

The processing of these events through the EAP has also exhibited not only the culture of Reliability and Compliance of these entities but also afforded the added benefit of producing valuable lessons learned for the industry which may have otherwise been lost had a formal compliance investigation been required.

- **NPCC Violations Identified From December 1, 2012 Through December 31, 2011**

  - Violations in the United States

    16 Notices of Possible Violation have been issued.

  - Violations in Canada

    None

- **Status of NPCC Violations Settlement Activities**

  - 20 violations in the United States and Canada are currently involved in settlement discussions, with various entities.

- **NPCC 2012 Compliance Audit Program**

  - NPCC has scheduled 5 On-Site Audits for 2012.
  - NPCC has also scheduled 10 On-Site CIP audits in 2012.
  - NPCC has scheduled 42 Off-Site audits in 2012; 1 is completed.
  - NPCC has scheduled 3 off-site CIP audits in 2012.
  - NPCC has developed the internal 2012 Spot Check Program schedule, and has targeted 400 spot checks of 85 registered TOPs, TOs, GOs and PSEs. Spot Checks for 2012 include IRO-005-2, Var-001-2, TOP-002-2b, PRC-004-2a and PRC-005-1a.

- All NPCC contract auditors will attend either of the two NERC auditor's workshops, and staff auditors will attend both.

Dec. 2011

NPCC Violation Summary

	Notice of Possible Violation[1]	Dismissal[2]	NAVAPS[3]	NOCV[4]	Settlement Discussion (Ongoing)[5]	Signed Settlement[6]	NOP[7]
FERC Enforceable	16	0	0	4	15	4	7
Canadian	0	0	0	0	5	0	

Table 1

1 Please refer to Table 2 for more details
2 Please refer to Table 3 for more details
3 Please refer to Table 4 for more details
4 Please refer to Table 5 for more details
5 NPCC and registered entities have not signed the settlement agreement
6 Please refer to Table 6 for more details
7 Please refer to Table 7 for more details

NOPV

# of Violations	Standard	Req.#
1	CIP-003-2	2
1	CIP-005-1	2
3	CIP-006-	1,2
3	CIP-007-2a	5,9
2	CIP-008-2	1
1	CIP-009-1	4
2	FAC-008-1	1
3	PRC-005-1	1,2

Table 2

Dismissal

# of Violations	Standard	Req.#

Table 3

NAVAPS

# of Violations	Standard	Req.#

Table 4

NOCV

# of Violations	Standard	Req.#
1	CIP-002-2	3
2	CIP-006-2	2,5
1	CIP-007-1	2

Table 5

Signed Settlement

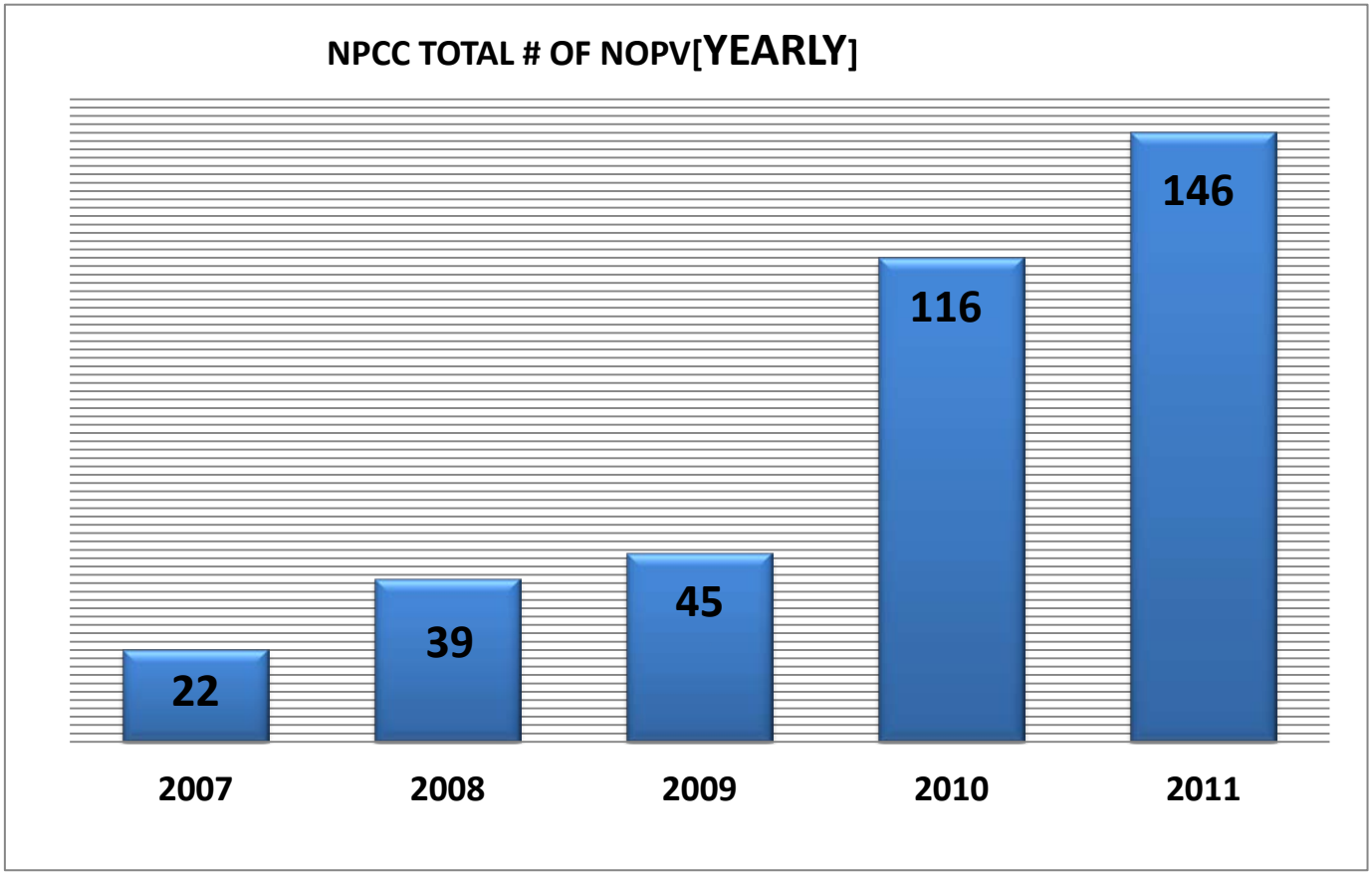
# of Violations	Standard	Req.#
1	CIP-007-2a	2
1	CIP-005-2	2
2	VAR-002-1	1

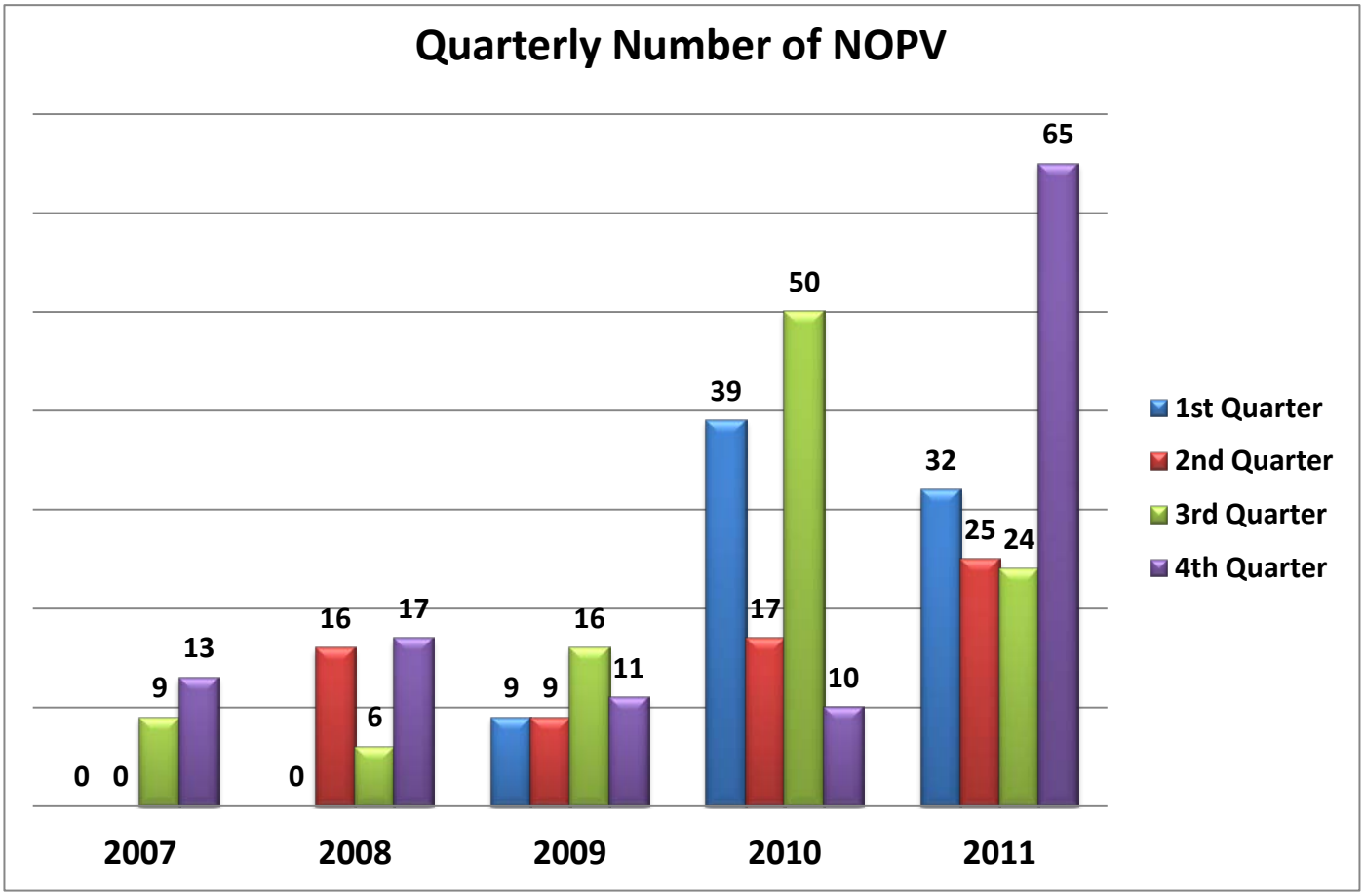
Table 6

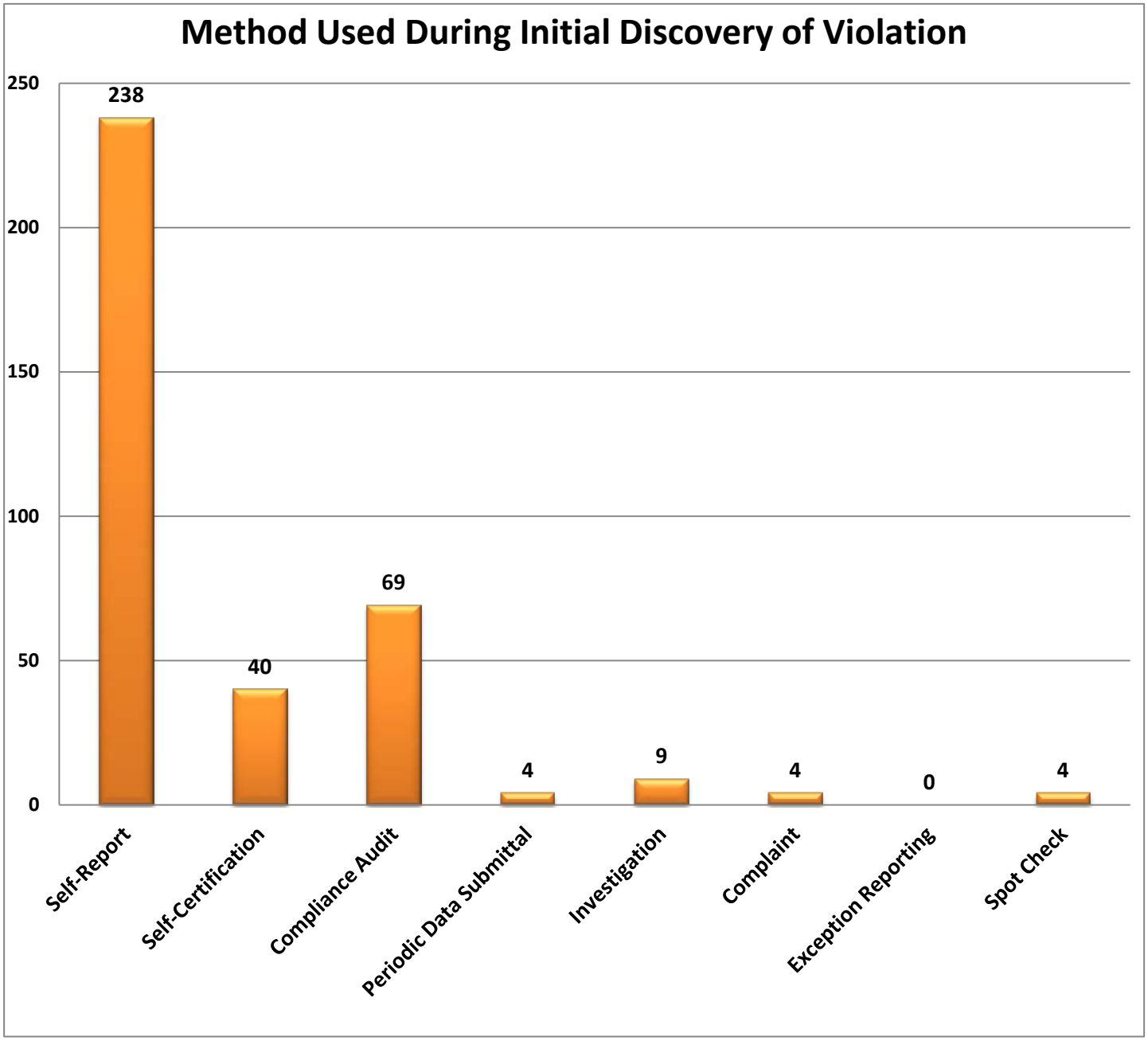
NOP

# of Violations	Standard	Req.#
2	CIP-004-1	4
2	CIP-006-1	1
1	COM-002-2	2
2	PRC-005-1	1,2

Table 7


NPCC TOTAL # OF NOPV[YEARLY]
22
39
45
116
146
2007
2008
2009
2010
2011


Quarterly Number of NOPV
0
0
9
13
0
16
6
17
9
9
16
11
39
17
50
10
32
25
24
65
2007
2008
2009
2010
2011
1st Quarter
2nd Quarter
3rd Quarter
4th Quarter


Method Used During Initial Discovery of Violation
250
200
150
100
50
0
238
40
69
4
9
4
0
4
Self-Report
Self-Certification
Compliance Audit
Periodic Data Submittal
Investigation
Complaint
Exception Reporting
Spot Check

NPCC, Inc.

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Date: January 18, 2012

To: NPCC Board of Directors

From: Philip A. Fedora - Assistant Vice President – Reliability Services

Subject: NPCC Reliability Coordinating Committee (RCC) Report

The following items were approval at the November 29, 2011 RCC meeting:

- ✓ September 8, 2011 Meeting Minutes
- ✓ RCC Roster Changes
- ✓ Task Force Roster Changes
- ✓ Interim Reviews of Resource Adequacy
  - Maritimes
  - Ontario
  - New York
- ✓ Interim Transmission Reviews
  - New England
  - Quebec
- ✓ Nova Scotia UFLS Implementation Plan
- ✓ NPCC August 14, 2003 Northeast Blackout Study – Task 5 Report
- ✓ 2011 – 2012 NPCC Winter Reliability Assessment
- ✓ New England Comprehensive Review of Resource Adequacy
- ✓ Quebec Comprehensive Review of Resource Adequacy
- ✓ Modification of the temporary Maxcys-Bucksport Type I SPS # 178
- ✓ Endorsement of Directories No. 9 & No. 10
- ✓ 2012-2013 Task Force Work Plans

Following approval of the 2012-2013 Task Force Work Plans, the 2012-2013 RCC Work Plan was finalized, and is attached to be considered for Board approval. The RCC activities planned for 2012 – 2013 are consistent with the NPCC 20112 Business Plan & Budget, the respective 2012-2013 Task Force Plans, and the RCC Scope of activities.

NPCC, Inc.

Reliability Coordinating Committee
Work Plan for Calendar Year 2012-2013

The following Reliability Coordinating Committee (RCC) activities planned for 2012 – 2013 are consistent with the NPCC 2012 Business Plan approved by the NPCC Board June 30, 2011 and the RCC Scope of activities approved by the NPCC BOD on February 3, 2009.

Core Reliability Criteria Functions

- ✓ Review and approve Comprehensive Area Transmission Reviews and Comprehensive Resource Adequacy Reviews brought forth before the RCC.

- ✓ Review and endorse new and revised Regional Reliability Directories and transmit a recommendation to the Full Members of NPCC for their final approval vote, in accordance with the NPCC Regional Reliability Directory Approval Process, and the NPCC Bylaws.

- ✓ As per the filed and approved "NPCC Regional Standards Development Procedure, oversee Task Force drafting and development of NPCC Regional Reliability Standards on the schedule set forth by the NPCC Regional Standards Committee and in accordance with the "NERC Reliability Standards Work Plan 2012 – 2013," as amended from time to time.

- ✓ Enhance the NPCC Regional Criteria Development process by encouraging and implementing procedures allowing for greater interregional interaction, communication and review, and by strengthening the design-based approach in regionally – specific criteria.

- ✓ Include any proposed revision of NPCC Criteria (as per NPCC Reliability Assessment Program (NRAP) schedule) during the development of the related NPCC Reliability Directories.

- ✓ Consider development of new NPCC regionally-specific, more stringent reliability criteria as part of the NPCC Reliability Directory process.

- ✓ Review NPCC Reliability Directories, procedures, guides, white papers, data, website(s) and databases to comply with NERC Reliability Standards and to promote reliability assurance in the NPCC Region.

- ✓ Review proposed NPCC Regional Standards, provide comments, during the period comments are being accepted, to the Regional Standards section of the NPCC Open Process for consideration by the respective NPCC Task Force Drafting Team. Support the NPCC Regional Standards Committee as necessary in the identification of potential reliability related concerns and assist with the

development and revision of Regional Standards, Variances, and/or Requests for Interpretations.

- ✓ Monitor developments at NERC for event related recommendations and incorporate into the NPCC Directories as necessary to meet the reliability objectives of Northeastern North America.

- ✓ Provide technical support to the NPCC Regional Compliance Committee as required in the review of NERC Standards, Compliance Application Notices "CAN"s, performing field tests and providing information for reports such as the NPCC's Cost Effective Analysis Procedure.

Provide technical support to the NPCC Regional Standards Committee's review of NERC Standards.

On-going activities

- ✓ Develop NPCC technical input and positions on NERC and FERC activities.

- ✓ Complete follow-up activities from the NPCC Blackout (2003) Study.

- ✓ Actively participate in the Eastern Interconnection Reliability Assessment Group (ERAG) activities.

- ✓ Actively participate in the established joint technical forum with Reliability *First* Corporation and the Midwest Reliability Organization to assure wide area, inter-regional coordination, by exchanging ideas and practices, including the identification of the need for appropriate near-term and long-term inter- regional studies, that further assure the reliability of the interconnected bulk power system.

- ✓ Review event analyses of operational disturbances both internal and external to NPCC in order to identify any lessons to be learned and recommend the necessary follow-up, including the recommendation of remedial or mitigating actions.

- ✓ Approve those Guideline/White Paper Documents brought forth to the RCC by the Task Forces.

- ✓ Review and approve, prior to issuance, 2012 and 2013 NPCC Summer Reliability Assessment. ***April 2012/2013.***

NPCC, Inc.

Reliability Coordinating Committee
Work Plan for Calendar Year 2012-2013

- ✓ Review and approve, prior to issuance, the annual NPCC Long-Range Adequacy Overview. ***December 2012/2013.***

- ✓ Review prior to issuance, the 2012-2013 and 2013-2014 NPCC Winter Reliability Assessment(s). ***November 2012/2013.***

- ✓ Review and approve any new or modified Type-I & Type II Special Protection Systems presented in 2012-2013.

- ✓ Conduct Joint Task Force Chairs Conference Calls/Meetings on a regular basis.

- ✓ Develop the 2013-2014 and 2014-2015 RCC Work Plan. ***November 2012/2013.***

- ✓ Review and approve 2013-2014 and 2014-2015 Work Plans for the NPCC Task Forces. ***November 2012/2013.***

- ✓ Review and approve any special assessments required in 2012-2013 as described in the RCC Scope.

- ✓ Carry out additional responsibilities in 2012-2013 not mentioned above but contained in the RCC Scope, or as directed by the NPCC Board.

NPCC, Inc.

Reliability Coordinating Committee
Work Plan for Calendar Year 2012-2013

The following Reliability Coordinating Committee (RCC) activities planned for 2012 – 2013 are consistent with the NPCC 2012 Business Plan approved by the NPCC Board June 30, 2011 and the RCC Scope of activities approved by the NPCC BOD on February 3, 2009.

Core Reliability Criteria Functions

- ✓ Review and approve Comprehensive Area Transmission Reviews and Comprehensive Resource Adequacy Reviews brought forth before the RCC.

- ✓ Review and endorse new and revised Regional Reliability Directories and transmit a recommendation to the Full Members of NPCC for their final approval vote, in accordance with the NPCC Regional Reliability Directory Approval Process, and the NPCC Bylaws.

- ✓ As per the filed and approved "NPCC Regional Standards Development Procedure, oversee Task Force drafting and development of NPCC Regional Reliability Standards on the schedule set forth by the NPCC Regional Standards Committee and in accordance with the "NERC Reliability Standards Work Plan 2012 – 2013," as amended from time to time.

- ✓ Enhance the NPCC Regional Criteria Development process by encouraging and implementing procedures allowing for greater interregional interaction, communication and review, and by strengthening the design-based approach in regionally – specific criteria.

- ✓ Include any proposed revision of NPCC Criteria (as per NPCC Reliability Assessment Program (NRAP) schedule) during the development of the related NPCC Reliability Directories.

- ✓ Consider development of new NPCC regionally-specific, more stringent reliability criteria as part of the NPCC Reliability Directory process.

- ✓ Review NPCC Reliability Directories, procedures, guides, white papers, data, website(s) and databases to comply with NERC Reliability Standards and to promote reliability assurance in the NPCC Region.

- ✓ Review proposed NPCC Regional Standards, provide comments, during the period comments are being accepted, to the Regional Standards section of the NPCC Open Process for consideration by the respective NPCC Task Force

NPCC, Inc.

Reliability Coordinating Committee
Work Plan for Calendar Year 2012-2013

Drafting Team. Support the NPCC Regional Standards Committee as necessary in the identification of potential reliability related concerns and assist with the development and revision of Regional Standards, Variances, and/or Requests for Interpretations.

✓ Monitor developments at NERC for event related recommendations and incorporate into the NPCC Directories as necessary to meet the reliability objectives of Northeastern North America.

✓ Provide technical support to the NPCC Regional Compliance Committee as required in the review of NERC Standards, Compliance Application Notices "CAN"s, performing field tests and providing information for reports such as the NPCC's Cost Effective Analysis Procedure.

Provide technical support to the NPCC Regional Standards Committee's review of NERC Standards.

<u>On-going activities</u>

✓ Develop NPCC technical input and positions on NERC and FERC activities.

✓ Complete follow-up activities from the NPCC Blackout (2003) Study.

✓ Actively participate in the Eastern Interconnection Reliability Assessment Group (ERAG) activities.

✓ Actively participate in the established joint technical forum with Reliability *First* Corporation and the Midwest Reliability Organization to assure wide area, inter-regional coordination, by exchanging ideas and practices, including the identification of the need for appropriate near-term and long-term inter- regional studies, that further assure the reliability of the interconnected bulk power system.

✓ Review event analyses of operational disturbances both internal and external to NPCC in order to identify any lessons to be learned and recommend the necessary follow-up, including the recommendation of remedial or mitigating actions.

✓ Approve those Guideline/White Paper Documents brought forth to the RCC by the Task Forces.

NPCC, Inc.

Reliability Coordinating Committee
Work Plan for Calendar Year 2012-2013

- ✓ Review and approve, prior to issuance, 2012 and 2013 NPCC Summer Reliability Assessment. ***April*** *2012/**2013.***
- ✓ Review and approve, prior to issuance, the annual NPCC Long-Range Adequacy Overview. ***December 2012/2013.***
- ✓ Review prior to issuance, the 2012-2013 and 2013-2014 NPCC Winter Reliability Assessment(s). ***November*** *2012/**2013.***
- ✓ Review and approve any new or modified Type-I & Type II Special Protection Systems presented in 2012-2013.
- ✓ Conduct Joint Task Force Chairs Conference Calls/Meetings on a regular basis.
- ✓ Develop the 2013-2014 and 2014-2015 RCC Work Plan. ***November 2012/2013.***
- ✓ Review and approve 2013-2014 and 2014-2015 Work Plans for the NPCC Task Forces. ***November 2012****/2013.*
- ✓ Review and approve any special assessments required in 2012-2013 as described in the RCC Scope.
- ✓ Carry out additional responsibilities in 2012-2013 not mentioned above but contained in the RCC Scope, or as directed by the NPCC Board.

NPCC, Inc.

2011 Corporate Goal Attainment Report

With Summarized and Auditable Scoring

Gateway Goal

The stretch level for the budget administration gateway goal is projected to be met. While there remains the potential for the independent auditors to make reclassifications which could yield slightly different numeric results for 2011, the goal attainment level should not be affected. During 2011, NPCC experienced significant recruiting challenges pushing existing staff extensively with massive efforts and long work weeks. NPCC's referral award program continues to be an extremely cost effective tool for recruiting qualified individuals and NPCC avoided substantial recruiting firm fees that could have been incurred in association with attracting qualified employees for open positions. Amendments with regard to the Bylaws of NPCC and changes affecting the future governance structure were well communicated and received near unanimous support within the Membership. As a result of successful efforts, NPCC implemented a hybrid Board structure effective January 1, 2012. Negotiation resulting in significant savings associated with selection of an Executive Search firm to assist the Corporate Governance and Nominating Committee in its comprehensive efforts to identify, screen, interview and ultimately select qualified Independent Directors to populate the newly formed Independent voting sector were extremely fruitful.

The 2011 Regional Entity Division Year End Budget Report which is required by NERC in late January, 2012 will be distributed via e-mail along with the unaudited financial statements for December 31, 2011 for total NPCC (Regional Entity & Criteria Services Divisions) prior to the February 1, 2012 meeting of the Board. The financial statements will indicate that receipts were on target for 2011 and expenditures were within the stretch goal parameter approved by the Board and consistent with an organization capable of significantly enhancing reliability and with lean operations achieved through major reshuffling of priorities within the year 2011.

Based on the staff self-assessment that follows, NPCC's performance with regard to both Regional Entity and Criteria Services Divisions 2011 Corporate Goal Attainment presented in this report is estimated as being "*Exceeds Target*" with a composite score of 95**%**.

2011 NPCC Goal Metric Summary – Ratings and Scores

Goal	*Rating*	*Score*	*Weighting (%)*	*Weighted Score*
#1	Stretch	100	10	**10**
#2	Stretch	100	20	**20**
#3a.	Stretch	100	15	**15**
#3b.	Stretch	100	15	**15**
#4	Target	80	5	**4**
#5	Target	80	10	**8**
#6a	Stretch	100	15	**15**
#6b	Target	80	10	**8**
			100	***95***

Goals	Threshold	Target	Stretch	Weight
Goal #1. Executive and Administrative	Operate within 103% of the initial 2011 Budget as well as applications approved by the Board from operating cash reserves. Approval by the Board and submission to the NPCC Membership of Amended NPCC Bylaws and Governance Change no later than [May 1]. Incorporation by NERC of at least 60% of NPCC Board policy input.	Operate within the initial 2011 Budget as well as applications approved by the Board from operating cash reserves. Approval by the NPCC Members of Amended NPCC Bylaws and Governance Change for submission to NERC Board of Trustees no later than [September 1]. Incorporation by NERC of at least 75% of NPCC Board policy input.	As an overall efficiency goal, operate within 95% of the initial 2011 Budget as well as applications approved by the Board from operating cash reserves. Approval by NERC and regulatory authorities of Amended NPCC Bylaws, and Governance Change for implementation effective January 1, 2012. Incorporation by NERC of at least 90% of NPCC Board policy input.	10

Goal #1 Executive and Administrative

Assessment of Goal Attainment: The Stretch attainment level for Goal #1 was achieved. NPCC's unaudited statement of activities for the period ending December 31, 2011 for the Regional Entity and Criteria Services divisions reflect expenditures totaling approximately 88% of budget. A revised Regional Delegation Agreement which incorporates the Amended and Restated NPCC Bylaws received FERC's unqualified approval for implementation, effective January 1, 2012. During 2011, NERC incorporated almost all of NPCC's submitted Board policy input in some 12 areas, with the NPCC recommendation for regulatory closure of mitigated possible violations submitted through the "Find, Fix and Track" process still under consideration by NERC.

Supporting Materials and Background

NPCC's unaudited statement of activities for the period ending December 31, 2011 for the Regional Entity and Criteria Services divisions reflect expenditures totaling approximately $12,137,105 as compared to a total 2011 budget of $13,812,600 or roughly 88% of budget. A Regional Entity division budget and cash reserve requirement totaling $13,081,110 was satisfied by NERC assessments to NPCC Load Serving Entity designees in a total amount of $12,652,610 for budget year 2011. The 2011 assessment was reduced by the application of penalty sanctions of $308,500 received through June 30, 2010 and 2011 stakeholder workshop fees ($120,000). The Criteria Services division budget totaling $1,020,471 was satisfied through NPCC direct assessments to its ISOs and Balancing Authority Areas. The 2011 assessment was reduced by the application of cash reserves totaling $664,691 for a total funding requirement of $349,600 for Criteria Services.

During 2011, NPCC submitted Board policy input in some 12 areas involving: a reduction in NERC's proposed staff additions and budget for 2012; initiation of selective field trails for proposed data intensive NERC metrics; a more transparent Compliance Application Notice development process; a phased approach to implementation of new Cyber standards; and, numerous NERC Rules of Procedure changes supportive of effective and efficient assurance of Northeast reliability.

With respect to overall ERO Enterprise strategy, NPCC successfully introduced explicit cost assessment into standards development and Adequate Level of Reliability considerations, and developed an industry-leading Cost Effectiveness Analysis Procedure. The NPCC Board's input shaped the ERO's top priorities for 2012 and focused future compliance efforts on risk-informed activities. NPCC also focused NERC compliance enforcement initiatives on providing efficiencies in Regional Entity and registered entity compliance efforts, and strived to obtain regulatory closure to mitigated possible violations.

Regarding the definition of the Bulk Electric System, NPCC's policy input helped establish a technical based exception process with clear criteria for excluded distribution facilities, protected Canadian authorities for alternative processes, and successfully advocated for an adequate transition period.

NPCC's input on Events Analysis improvements shaped the industry-based process and NPCC staff led the ERO's implementation. NPCC policy recommendations also enhanced industry-wide learning opportunities in a revised NERC Alert process and successfully streamlined the Alert response requirements.

Working with NERC, NPCC staff developed a revised Regional Delegation Agreement which incorporated the Amended and Restated NPCC Bylaws and the Board's endorsed responsibility for NPCC to act as the Compliance Enforcement Authority for the registered entity functions performed by the Western Electricity Coordinating Council. Following the NERC Board of Trustees unanimous approval, NPCC conducted significant outreach efforts with FERC staff and ultimately obtained FERC's unqualified approval of implementation of the revised RDA effective January 1, 2012.

NPCC organized a meetings of the NPCC Governmental/Regulatory Affairs Advisory Group in conjunction with the NPCC 2011 General Meeting, that provided an opportunity to review NPCC reliability interests with Federal/State/Provincial regulatory and/or governmental authorities, and provide a forum for industry and governmental/regulatory representatives to exchange information and discuss the development of recommendations to the NPCC Board. A FERC representative discussed the recent Commission Order 1000, NERC presented the results of their recent scenario assessment of anticipated reliability impacts from proposed EPA regulations, and ISO-NE and NERC representatives provided an update on anticipated upcoming Gas/Electric Interdependency analysis. In addition, a status of the Eastern Interconnection Planning Collaborative activates was provided.

Additional 2011 NPCC Accomplishments

(Opportunities that emerged after the NPCC Goal Metrics or Components were approved)

In the NPCC IT area in 2011 there were a number of notable accomplishments:

- Implementation of a credit card billing system was rolled out for the December Compliance and Standards Workshop. Previously, participants made payments via check.
- Initiated the development of the NPCC Purchase Order program to replace several manual processes and improve efficiency, accuracy and consistency for many day to day repetitive activities. Areas enhanced include: inventory review, order placement and approvals, receipts, context sensitive vendor and service lists and codes to maintain complete order history, payments, pricing and usage volumes. Compliance staff worked collaboratively with Registration staff, to extend the design of the electronic application

to encompass payroll and financial information. This tool has been implemented and will greatly enhance preparations for financial audits.

- A "Wiki" site was added to the Compliance section to promote the sharing of issues and information.
- An Event Capture Scheme/database was developed for the Event Analysis program
- Secure file transfer system was set up for the secure transfer of CEII information
- NPCC Chaired the Steering Group for IT at NERC, ITSG which will help develop and define NERC's IT strategy and provide an avenue into NERC's IT decisions for our members.
- NPCC designed and put into production, a new website with improved user interface and functionality
- NPCC staff provided a rigorous review of the NPCC's Disaster Recovery/Business Continuity Plan. Detailed comments were provided to the NPCC IT group so that they could enhance the robustness and utility of the Plan to better ensure its implementation during a disaster. Changes have been incorporated into the plan to reflect lessons learned during actual emergencies.

Goals	Threshold	Target	Stretch	Weight
Goal #2. Reliability Standards Program	NERC Support Activity Actively participate in the version 5 Cyber Security Standards development and effectively promote the Northeast's stakeholders comments. NPCC Regional Standard Activity Develop new Regional Standards web pages – by 12/11. NPCC Criteria Activity Develop NPCC Glossary of Terms based on Phase 1 of the Directory Project for RSC approval – by 12/11.	Attainment of Threshold Goal and: NERC Support Activity Develop a "triage" process to efficiently and effectively utilize NPCC's internal and external resources to review standards – by 12/11. NPCC Regional Standards Activity Develop and post 3rd Regional Standard and implement a Standards Quality Review process within NPCC for regional standards – by 12/11. NPCC Criteria Activity Achieve RSC endorsement of an NPCC Directory Development Manual – by 12/11.	Attainment of Target Goal and: NERC Support Activity Assist in the development of enhanced interpretation procedures and prioritization processes for ERO standards – by 12/11. NPCC Regional Standard Activity Post enhanced NPCC Regional Standards Process Manual incorporating new NERC and FERC processes suitable for posting. NPCC Criteria Activity Complete set of Phase 2 NPCC Directory Project initial translations and ballot two directories – by 12/11.	20

Goal #2 Reliability Standards Program

Assessment of Goal Attainment: The Stretch attainment level for Goal #2 was achieved (100% of Stretch level achieved). In addition, there was a furtherance of the deliverables beyond the stated goals. All the objectives identified in the Threshold and Target categories were fully achieved by, and in most cases well prior to, the dates indicated. During 2011, NPCC staff participated on the Standards Committee Process Subcommittee in the development and enhancement of a NERC standards project prioritization tool, and a "Rapid Revision" process to address the "repair" of standards issues identified through the interpretation and compliance processes. NPCC also participated in commenting on the NERC Compliance Application Notice

process (CANs) which is another enhancement of the "suite" of NERC tools to provide clarity. In the last Quarter of 2011 the NPCC RSC proposed changes to the NPCC Regional Reliability Standards Development Procedure to reflect changes within NERC and FERC and approved posting of the enhanced standards development document in December for a 45 posting period for comments. In December, initial draft translations of all the directories was completed and two NPCC Reliability Directories, #9 and #10 Generator Verification Directories, which reflected Phase II of the Directory Project efforts were approved by the NPCC Full Member Representatives in December of 2011.

Supporting Materials and Background

The 2011 NPCC BOD approved Goals for the standards program area were based on three categories of activities as follows: support of NERC activities, NPCC Regional Standards Activities, and NPCC Criteria Related Activities.

NERC Support Activities

NPCC was proactively engaged in a number of NERC standards, initiatives and process developments. Included in these activities, is the continuing active involvement of Staff and NPCC Task Force on Infrastructure Security and Technology (TFIST) members in the development of Version 5 CIP (Cyber Security) standards. NPCC conducted numerous meetings of the NPCC Regional Standards Committee (RSC) and TFIST on the Version 5 proposal, participated in several webinars and made presentations of the materials to the NPCC Members at Compliance Workshops. NPCC staff also participated in numerous standard drafting team (SDT) meetings and provided the Northeast perspective and ensured that the comments submitted to the team were understood and addressed. The latest draft version of the standard, which incorporates significant Northeast input, still requires additional work to make it acceptable and is before the industry in the initial balloting/commenting process.

The RSC developed a Triage process to more efficiently and effectively utilize subject matter expertise from the Northeast to improve the quality of NERC's standards and provide NPCC Member input to the standards' development. NPCC staff participated on the Standards Committee Process Subcommittee "SCPS" in the development of the NERC project prioritization tool. The SCPS also developed a "Rapid Revision" process which is being implemented to address the "repair" of standards issues identified through the interpretation and compliance processes. The SCPS also has a subgroup, led by NPCC, which is currently engaged in developing a system to insure that drafting team members are properly qualified and revising the SDT nomination processes. The RSC has also provided input to the Compliance Application Notice (CAN) Process which is used as an alternative for the industry to more quickly clarify compliance application issues, which previously could only be addressed through the formal interpretation process.

Additionally, the RSC reviewed more than 13 individual projects and sent out ballot recommendations and/or lists of issues and concerns to the ballot body participants in NPCC. The RSC also commented on more than 45 individual standard projects, other NERC documents, and 24 CANs, while expressing the Northeast perspective of NPCC's Members on the posted materials. The NPCC RSC also tracks SDT membership to ensure that all NERC standard drafting activities are staffed with either NPCC Member participants or NPCC Staff to ensure the reliability objectives of the Northeast are represented. NPCC staff has also filled critical gaps when necessary on NERC Committees, Subcommittees, Task Forces and Working Groups to ensure representation is maintained and the Northeast's perspectives are promoted. The NPCC Standards program area has also provided support to the following groups at NERC: the Standards Committee, the SCPS, the Functional Model Working Group, the Reliability Metrics

Working Group, the System Protection and Control Subcommittee, and the NERC Regional Standards Group (RSG). Significantly, the RSG is currently developing a number of initiatives that will focus on consistency between regions, providing clarity to the variance and Regional standard processes and the criteria for initiating them. The RSG has also been actively engaged in reviewing the NERC Evaluation Procedure for Regional Standards.

NPCC Standards Staff, taking into consideration the concerns of the RSC, participated in the NERC Standards Committee Process Subcommittee (SCPS). The SCPS developed enhancements to the Project Prioritization Tool and used these enhancements to develop the draft of the 2012-2014 Standards Development Workplan. The enhancements included consideration of costs and regulatory deadlines. The enhancements also assist with the division of the NERC projects into three prioritizations based on: reliability, time and practicality. The SCPS also provided input into the various interpretation initiatives, the Compliance Application Notice process, as well as the rapid revision procedure for standards. The rapid revision procedure will provide a procedure to expedite revisions to standards that may be ambiguous or have vague requirements. In addition NPCC staff developed a revised set of criteria for NERC standard drafting team selection to ensure the proper expertise level of potential team members.

NPCC Standards and Legal staff, also participated in "Quality Review (QR) Training" at NERC and is now assisting the ERO with reviewing standards for the necessary level of quality prior to postings. These QRs focus on ensuring that the standards have the necessary technical writing clarity, in addition to adequate compliance and legal review along with proper formatting and style.

NPCC staff also made classroom presentations at the NPCC's Fall Compliance Workshop on the Disturbance Monitoring and Automatic Underfrequency Load Shedding regional standards.

NPCC Regional Standard Activities

2011 was indeed a landmark year for NPCC in the area of Regional Standards. The NPCC Board of Directors approved the first NPCC Regional standard, (Disturbance Monitoring "DM", PRC-002-NPCC-01), and it was subsequently approved by the NERC Board of Trustees and filed with the Federal Energy Regulatory Commission "FERC". NPCC staff worked with NERC legal in excess of 4 months to produce the filing and in addition conducted two teleconferences with the FERC Office of Enforcement and Office of Electric Reliability to review the intent of the standard and to answer commission staff questions subsequent to the NERC filing. PRC-002-NPCC-01 was approved by the FERC on October 20, 2011. Importantly, FERC issued no Directives to modify the standard. This is a testament to the high quality of the standard and the effort by the NPCC SDT, members, and staff. Also the Members of NPCC recently approved the PRC-006-NPCC-01 Automatic Underfrequency Load Shedding Program – a Regional standard developed from Directory No. 12.

In addition, the RSC developed and piloted an NPCC Cost Effectiveness Analysis Procedure "CEAP". This is a two phase analysis that performs a high level Cost Benefit study upon the initial consideration to develop a Regional reliability standard. The RSC will use this Phase 1 of the CEAP to determine if a standard is of sufficient reliability benefit, given the potential costs, to justify moving it forward to develop. Once the draft standard has been developed the second phase of the procedure is to determine if there are any more cost efficient ways of achieving the reliability objective of the standard and if the standard, in the opinion of industry, is cost effective in achieving that objective.

During the past year staff has made presentations to the Board, RCC, RSC, CC and the North American Generator Forum in the areas of Cost Effectiveness and Compliance support. The NPCC Cost Effectiveness Analysis Procedure was posted and shared at NERC as a foundation document on which to build a similar initiative for ERO standards.

In August of 2011, a new NPCC website with increased functionality was put into production. The new website provides more transparency, is easier to navigate and incorporates "progress" bars for the individual standards to allow the stakeholders to immediately identify where in the process the individual standards may currently exist.

NPCC began work on the third NPCC Regional standard, Reserve Sharing BAL-002-NPCC-01. The standard was drafted and posted on the NPCC website for an initial comment period. The RCC assigned the drafting of the standard to the Task Force on Coordination of Operations. Additionally, industry participants were solicited for regional SDT appointment.

During 2011 NPCC also worked with the RSG to review the consistency issues between the regions and developed a first draft of the revised NPCC Regional Standards Development Process. The standard has been posted on the NPCC website for comment and also submitted to NERC for posting on their website to ensure "interregional" comments are addressed. The proposed revisions to the process will implement proposed efficiencies, address gaps, introduce new attributes to promote quality and increase flexibility of NPCC's standards development.

NPCC Criteria Related Activities

A NPCC Glossary of Terms developed from the Phase 1 Directory translation project was approved by the RSC during 2011. The new Glossary replaced Document A07 and is posted in the Directory section of the NPCC website. The Glossary contains references to where the NPCC terms are used and also whether the terms may differ from NERC Glossary Terms so that the Task Forces of NPCC can review the differences and move towards eliminating instances where the definitions differ by either adopting the NERC term, or initiating the NERC Standards Development Process to change the NPCC defined term to the NERC term.

In October of 2011 the RSC also approved a new Directory Development Manual. This Manual was developed to assist the NPCC membership in understanding how to coordinate revisions to a reliability Directory, how to develop a new one, seek interpretation to Criteria in the Directory and revise the NPCC Glossary. The Manual is posted on the NPCC website in the Directory section for member use and will provide some insight on how to coordinate reviews of Directory's when revisions to sections of a Directory are necessary by multiple Task Forces.

All the initial Phase 2 drafts of existing Directories have been completed by NPCC staff and are available for Task Force use as a starting point for their revisions and deliberations. The TFCO working with NPCC Standard staff completed the development of the first Phase 2 Directory translations when Directory No. 9 and No. 10 for Generator Verification were approved by the TFCO and the Reliability Coordinating Committee "RCC" in November 2011. The Directories were balloted and approved by the Full NPCC Membership in December 2011.

The Phase 2 reformatting of Directory No. 1 Design and Operation of the BPS and a new Directory No. 6 outlining the process for Reserve Sharing were both drafted by NPCC Task Forces under RSC oversight and are moving through the review process.

Goals	Threshold	Target	Stretch	Weight
Goal #3a. Compliance Monitoring and Enforcement Program (CMEP) - Internal Quality Enhancement Program (QEP)	Distribute a NPCC Culture of Compliance Survey to selected registered entities and evaluate responses submitted and revise Survey as necessary – by 4/11. Demonstrate a 5 % efficiency gain in the processing of violations that result in either a signed settlement agreement or a Notice of confirmed violation – by 12/11	Attainment of Threshold Goal and: Distribute enhanced Culture of Compliance Survey to all NPCC registered entities; evaluate 75% of registered entity responses – by 12/11. Demonstrate a 10% efficiency gain in the processing of violations that result in either a signed settlement agreement or a Notice of confirmed violation – by 12/11	Attainment of Target Goal and: Evaluate 100% of registered entity responses and develop and disseminate corrective action programs to provide assistance to 50% of the lesser performing (lower graded) entities – by 12/11. Demonstrate a 15 % efficiency gain in the processing of violations that result in either a signed settlement agreement or a Notice of confirmed violation – by 12/11	15

Goal #3a Compliance Registration and Enforcement

Assessment of Goal Attainment: The Stretch attainment level for Goal #3a was achieved (100% of Stretch level achieved). Goal #3a consisted of two parts: 1) the Culture of Compliance Survey Initiative and 2) the Improving the Efficiency of Violation Processing Initiative. NPCC staff developed and distributed a total of 165 NPCC Culture of Compliance Surveys, covering all 287 NPCC registered entities. The staff evaluated 100% of the 146 survey responses received. In 2011, the enforcement staff, despite an increase in personnel of 11%, had a workload increase of 26%. In 2010 there were 72 violations closed that consisted of dismissals, signed settlement agreements or issuances of NOCV's. In 2011, through December 20, there were 130 violations closed via the same activities. Taking into consideration the increase in enforcement staff and the increase in number of violations closed, a violation processing efficiency increase of 61% over 2010 was realized during 2011, by the NPCC enforcement staff.

Supporting Materials and Background

The Culture of Compliance Survey evaluations consisted of reviewing the material sent by each registered entity, conducting one-on-one assessment phone calls with each survey submitter, rating each registered entity, and identifying Examples of Excellence and Best Practices. The survey initiative is documented in the "Report on 2011 NPCC Culture of Compliance Survey Initiative", which is posted on the NPCC Website and available on the CDAA portal. The report includes a compilation of the Examples of Excellence and the Best Practices identified which present potential mechanisms or corrective action programs for registered entities to consider when reviewing or enhancing their internal compliance programs.

A detailed presentation, on the 2011 NPCC Culture of Compliance Survey Initiative, was made at the 2011 Fall NPCC Compliance and Standards Workshop held on December 14 -16, 2011 and attended by over 200 people. A follow-up webinar will be held in January 2012 with all NPCC registered entities to discuss the report in detail.

NPCC Culture of Compliance Survey Initiative and Development

NPCC defines a Culture of Compliance as an environment in which a registered entity demonstrates continuing awareness and commitment to meeting its obligations as they relate to the NERC Reliability Standards. A sound and effective Culture of Compliance is a critical component in assuring the reliability of the Bulk Electric System.

NPCC viewed this initiative as a tool for improvement, to be used by the registered entity to ultimately improve the reliability of the Bulk Electric System. The goals of the initiative were for:

- NPCC to gain an overall perspective of the culture in the region;
- each registered entity to identify opportunities for growth or confirm that processes were already in place; and,
- NPCC to identify and share, with all registered entities, Examples of Excellence and Best Practices.

NPCC developed a survey to evaluate a registered entity's Culture of Compliance based on the following FERC policy statements: the October 2005 Policy Statement on Enforcement (a.k.a. "13 Questions"); the May 2008 Revised Policy Statement on Enforcement; the October 2008 Policy Statement on Compliance; and, the September 2010 Revised Policy Statement of Penalty Guidelines.

Each of the FERC policy statements highlighted attributes and/or characteristics that the Commission believed a registered entity's internal compliance program should contain to ensure an effective Culture of Compliance and therefore create an environment conducive to a reliable Bulk Electric System.

Implementation of Initiative

In January 2011, an initial Culture of Compliance Survey was approved by NPCC Compliance Committee and distributed, as part of initial trial test, in February, 2011. The initial trial test (Phase 1) was conducted with a select number of registered entities (58), representing a cross section of entity types (functions, size, etc.). A webinar was held with trial test participants in advance of the submittal of survey responses to clarify the purpose of the survey and answer questions. A post submittal webinar was also held with trial test participants to allow them to discuss the survey process and provide any comments on either possible process changes and/or survey changes to NPCC Staff.

A revised and enhanced survey was then developed and presented to NPCC Compliance Committee for review and approval. The Compliance Committee approved the enhanced survey at its June, 2011 meeting. The enhanced survey was sent to all remaining NPCC registered entities.

Evaluation of Survey Responses

NPCC used the generic categories of the functional model to determine whether the minimum requirements of a culture of compliance existed. The categories for relative comparison used by NPCC Staff were RC/BA, TO/TOP, GO/GOP, DP/LSE, and PSE. These categories are characterized by the common content, common themes, and common depth of data provided by an entity in that particular category.

NPCC Staff performed the subjective analysis of each survey response and placed each survey into one of three measurement buckets:

- "Green" – The survey response indicates that the entity meets or exceeds all minimum characteristics of a favorable Culture of Compliance;
- "Yellow" – The survey response indicates that the entity does not meet all minimum characteristics of a favorable Culture of Compliance; and,
- "Red" – The survey response indicates that the entity meets few or no minimum characteristics of a favorable Culture of Compliance.

The overwhelming majority of survey responses had a "Green" culture and an inherent fundamental understanding of their compliance obligations. A minority of responses were assessed as a "Yellow". In each of those cases, a feedback phone call was used to verify and pursue additional questions to assist the entity in attaining a higher measurement bucket. There were no survey responses that were assessed as a "Red" culture.

NPCC staff completed its evaluation of all surveys received at the end of December 2011. In addition, NPCC Staff put forth tremendous effort and time to coordinate a feedback phone call with every Registered Entity that provided a survey response. This resulted in 146 phone calls that encompassed 265 Registered Entities being made over four months. For the overwhelming majority of responses, the feedback calls served as an acknowledgement to the compliance personnel at each entity that NPCC staff viewed the culture exhibited in their survey response in a positive light. As stated earlier, a minority of the calls served to first clarify the contents of the response followed by the acknowledgement that NPCC staff viewed the culture exhibited in a positive light.

The "Report on 2011 NPCC Culture of Compliance Survey Initiative" will be sent to the Primary Compliance Contact at each of the 22 Registered Entities that did not provide a survey response. This will ensure that those entities have the opportunity to review the Examples of Excellence and Best Practices that could potentially enhance their compliance programs.

Dissemination of NPCC's Initiative to NERC, Other Regional Entities and Trade Associations

The activities undertaken by NPCC related to the Culture of Compliance Survey have been shared with various sectors of the industry which include: the NERC Board of Trustees Compliance Committee, the Electric Reliability Organization Compliance and Enforcement Management Group (ECEMG), the North American Generator Forum (NAGF), the North American Transmission Forum (NATF), and the Large Public Power Council (LPPC). In addition, the survey is being considered as the model for the culture of compliance component of NERC's forthcoming Entity Assessment efforts.

In 2011 NPCC demonstrated a significant increase in the efficiency of processing violations that it has identified during its implementation of the Compliance Monitoring and Enforcement Program (CMEP). The metric used to demonstrate this increase in violation processing efficiency was the percentage increase in the number of violations closed in 2011 per enforcement staff member versus the number of violations closed in 2010. NPCC defines a violation as closed when the NPCC Enforcement Staff has obtained a signed Settlement Agreement; issued a Notice of Confirmed Violation (NOCV) or dismissed a violation.

In 2011, the enforcement staff, despite increased in personnel of 11% and had a workload increase of 26%. In 2010 there were 72 violations closed that consisted of dismissals, signed settlement agreements or issuances of NOCV's. In 2011, through December 20, there were 130 violations closed via the same activities. Taking into consideration the increase in enforcement

staff and the increase in number of violations closed, a violation processing efficiency increase of 61% over 2010 was realized during 2011, by the NPCC enforcement staff.

Efficiency Improvement Factors

There are a number of factors that have contributed to this increase in violation processing efficiency. These factors include:

- The implementation, by NPCC, of the NERC-wide Administrative Citation Process (ACP) in the overall enforcement process. This process was introduced at the end of 2010 and fully implemented by NPCC in January 2011. The ACP process was introduced to streamline the enforcement process by expediting the closing of administrative type violations which had a minimal to moderate impact to the reliability of the Bulk Electric System (BES). NPCC was a leader in the use of the ACP process from its onset and provided a number of candidates for the initial and subsequent ACP filings. NPCC also promoted the use of this process at various NERC groups.
- The implementation, by NPCC, of the Find, Fix, and Track Process (FFT). This initiative was introduced in August 2011 and implemented in September, 2011 and augmented the ACP process to further streamline the enforcement process. The FFT process focuses on violations where the entity has already implemented corrective actions and would only require the submittal of mitigating activities and a certification to prove compliance. In addition these violations are for those that pose a lesser risk (minimal to moderate) to the reliability of the BES. As with the ACP process NPCC was very supportive of the FFT process and promoted its use among other Regional Entities and NERC. The ACP and FFT processes, by focusing on violations that have less of an impact on the reliability of the BES, has allowed the NPCC Enforcement Staff to focus greater resources on the processing of more serious violations that have higher impact to the BES.
- The development of new enforcement processing tools and the enhancement of existing enforcement processing tools. These included the :
    - ✓ Introduction of the Compliance Information Tracking System (CITS). This new software enhancement was implemented to electronically track all violations submitted by the registered entities or found by NPCC. This enhancement allows for all information to reside in one database and greatly improves the review process of violations, the electronic tracking status of mitigation plans and provides consistency in the reporting of violation processing data among the registered entities, NERC and other Regional Entities. CITS also replaced manual workbooks, which were cumbersome and inefficient for processing the data, with an electronic web service that allows for direct data transfer to NERC. NPCC Staff played an integral role in the integration of CITS both internally at NPCC, and externally with NERC. The deployment of a letter generator, a future enhancement to CITS that is currently under development, will add functionality that will allow the NPCC Enforcement Staff to generate the required letters for processing violations under the CMEP rules. This enhancement will eliminate duplicative work and provide uniformity in documentation wording. In addition, the CITS Letter Generator Tool will have a reporting mechanism that will notify Enforcement staff on the status of outstanding letters that are required to be sent.
    - ✓ Enhancements to the NPCC registered entity portal (known as CDAA). The addition and enhancements of new forms have been implemented into the enforcement process. These upgrades have automated the process and resulted in the elimination of the manual processes that existed and were related to the development of self-report forms; mitigation plan forms; milestone update forms;

extension forms; Certification of Completion forms; and electronic authorized signature required on applicable forms.

- ✓ The development of the Violations Reporting System (VRS) that provides a tool/mechanism for keeping track of all NERC reliability standard violations being processed by NPCC enforcement staff. VRS enables NPCC enforcement staff to store significant amounts of violation processing data and use this data to analyze enforcement processing activities. In addition it automatically tracks the progress of violation processing and provides statistics about violations within NPCC. These statistics include but not limited to the following: Notice of Possible Violations (NOPV) Reports/Statistics; Yearly Discovery Methods; Notice of Alleged Violations and Penalty Sanctions (NAVAPS) Reports/Statistics; Settlement Reports/Statistics; Dismissed Violations Reports/Statistics; Notice of Confirmed Violations (NOCV) Reports/Statistics; Closed Violations Reports/Statistics; Carried-Over Violations Reports/Statistics; Yearly Violations Processing Duration Report/Statistics. VRS allows the NPCC staff to significantly improve its assessment of the processing of violations, thereby being able to make informed decisions and continue to improve the efficiency of processing of violations.
- ✓ Enhancements to existing registration processes, particularly those related to the selling, transferring, and/or merging of existing assets. These activities in the past have caused significant delays in the processing of outstanding violations as the changing asset ownership issues are resolved.

Goals	Threshold	Target	Stretch	Weight
Goal #3b. Compliance Audits and Investigations	Develop a corroborating evidence document library of registered entity supporting material for TFE justifications – by 6/11 Review and acknowledge audit feedback from registered entities within 60 days of receipt.	Attainment of Threshold Goal and: Make the TFE library available and usable by NPCC registered entities – by 9/11. Dismiss or implement feedback suggestions from registered entities within 120 days of receipt.	Promote NPCC TFE library to NERC and other Regional Entities to drive consistency in TFE processing – by 12/11. Develop a database of implemented feedback items and disseminate to all registered entities – by 12/11.	15

Goal #3b Compliance Audits and Investigations

Assessment of Goal Attainment: The Stretch attainment level for Goal #3b was achieved (100% of Stretch level achieved). NPCC developed a corroborating evidence document library for use in supporting TFE requests. This library is a "living" repository of supporting documents that is added to as more documentation becomes available. These documents enable expedited review of TFE's by referencing the known device and checking the corroborating documentation as justification. Prior to the library, each entity would have to obtain the information on a case-by-case basis. Also, database of responses to the implemented feedback items form audits has been developed to document and disseminate the suggestions and applicable resolutions to the registered entities via the NPCC compliance website. The results of 2011 Audit Feedback are posted on the NPCC public website.

Supporting Materials and Background

The structure of the TFE library was finalized and populated with documents for use by NPCC registered entities as early as February 2011, and finalized by April 2011 (before the Threshold date of 6/11). The TFE library is needed for instances where a known problem exists with certain equipment and the referenced TFE. For example, the Schweitzer Engineering Laboratories, Inc. process for mitigating malware risk to embedded devices, details Systems Security Management and outlines requirements for Malicious Software Prevention under CIP-007-1. Availability of the TFE library for use by NPCC entities has been announced as early as the NPCC 2011 Spring Compliance Workshop (before the Target Date of 9/11) and throughout the entire year via posting on NPCC's website and again at the NPCC Fall Compliance Workshop. NPCC has promoted the use of the TFE library to NERC and the other regions at the regional quarterly working group meetings held in April, July and December 2011 (before the Stretch date of 12/11). NERC has accepted the NPCC initiative and has encouraged the other Regional Entities to produce the same.

Enhance TFE Review Process

In addition to the corroborating evidence library, NPCC Compliance staff has developed consistent, effective and efficient processes to implement the review of TFEs. NPCC works with NERC and the other Regional Entities to document these processes and organize and promote their use via quarterly meetings.

NPCC has developed training presentations that have been presented at the NPCC Spring and Fall 2011 Compliance Workshops. New TFE processes and procedures are communicated via announcements and postings on the NPCC CDAA website.

NPCC's TFE Team has been instrumental in suggesting and initiating changes to the TFE process to make it more efficient and streamlined, thus reducing the impact on available resources.

Process Improvements by Incorporating Feedback from Compliance Audits

During audit exit briefings, NPCC solicits feedback from the audited entity via completion of the NERC Audit Feedback form. NPCC tracks, reviews and acknowledges feedback forms from each audited entity within 60 days of receipt. If a feedback form was not provided to NPCC in a timely manner, NPCC contacted the entity to remind them to complete the form and submit it. NPCC developed a tabulation and grading system to evaluate the audited entity responses for all the questions on the NERC feedback form. NPCC has a success rate of receiving nearly 100% of the feedback forms for their audits which is higher than other Regional Entities. All comments are reviewed, and any negative comments are looked upon as opportunities for improvement. Average score on seven of the nine questions was 9+ on a scale of 0-10 with 10 being the highest. Entity feedback has been very positive. The average score on two of the nine questions were lower for the following reasons. One question regarding "impact to work" received the same negative responses from several audited entities that were part of the same parent company, and from smaller entities. The second question regarding "suggestions from audits" is being further investigated to determine whether the audited entity's compliance program warranted any suggestions. Some of the low scoring concerns NERC mandated process factors that NPCC cannot change. All comments, including negative or non-implementable suggestions, have been discussed with the submitting entity within 120 days of their receipt.

NERC and FERC have observed several NPCC on-site audits and provided feedback leading to improvements in the NPCC audit process in the areas of interviewing, CEII data handling , rigor

in data requests and evidence tracking sheet security, audit team caucusing and end-of-day wrap-up with entity. Improvements to NPCC audit process are continually being made and suggestions are addressed at bi-monthly Auditor meetings. A database of responses to the implemented feedback items has been developed to document and disseminate the suggestions and applicable resolutions to the registered entities via the NPCC compliance website. The results of 2011 Audit Feedback are posted on the NPCC public website and are updated as more feedback is received.

Prepare a new NPCC Compliance Procedure for Mis-operation Reporting

NPCC staff took an active role in the development and implementation of a process and commensurate reporting templates, to address Protection System Mis-operations. This was the NERC President's "Top Priority Issue for Bulk Power System Reliability" in 2011. The process leveraged NPCC resources and actions to support the ERO-RAPA ALR4-1 metric, PRC-003 & PRC-004 compliance and TADS update. NPCC Compliance staff met with RAPA staff to develop a multi-purpose entity guidance document describing the bases, stakeholders, forms, actions, schedules, submittal process, and relationship between mis-operation quarterly reporting and compliance.

The new non-binding guidance document provides an overview of all the actions related to Protection System Mis-operation Reporting and the various stakeholders (entity and NPCC) that affect, and are affected by, mis-operations. The guide is a comprehensive and instructional document for applicable registered entities in the logistics, forms, deadlines, scope and processes for Mis-operation Reporting form to support the entities' required actions to meet multiple NERC requirements - Compliance, NERC metrics (ERO-RAPA) and NERC trending (TADS). The process was presented at the NPCC 2011 Spring Compliance Workshop. The guide, its references, blank reporting templates, and samples were posted on the NPCC public website in June 2011 and are provided as links in the NPCC quarterly reminder to the entities.

NPCC will also ensure all registered entities are using the mis-operation tracking process to provide a self check when Self Certifying compliance for the reporting period. This suggestion has been provided in the non-binding guide and in the quarterly reminder to the registered entities when the Mis-operation Reporting Template is due.

Coordination among Situation Awareness, Events Analysis and Compliance

In conjunction with the development of NERC's continent-wide Event Analysis Process (EAP), NPCC developed a Workflow Plan to coordinate the NPCC's Situational Awareness (SA), Event Analysis (EA) and Compliance Investigations and Enforcement Groups' efforts to create a more effective and efficient method for reviewing events. To this end, NPCC Compliance Investigation has authored a Compliance Instruction document CI-16 "Conducting NERC ERO Event Analysis Process" which specifies the roles and responsibilities of NPCC's SA, EA and Compliance Staff members for implementing the EAP within the NPCC region.

NPCC, together with SERC, has developed an Event Capture System application to track events occurring within the NPCC region. This application enables the tracking of the event from reporting inception through interim stages (event analysis/lessons learned/corrective actions) and finally compliance closure or handoff to Compliance Investigation and/or Enforcement. This application has been implemented during the Event Analysis Process phase II field trial. With NPCC's collaboration, SERC has enhanced their application and supports NPCC's suggestion to NERC to adopt the NPCC/SERC "best practice" as the model for the other Regional Entities.

Secure Data Submittals

To assure confidentiality of submitted data for the various components of the compliance program, registered entities are required to use the NPCC secure FTP site. To increase efficiency of the current process, NPCC implemented a clientless FTP solution. The new clientless solution has been well received by NPCC registered entities for several reasons such as no longer needing to install an FTP client on the entity computers and no longer having to open ports on the entity firewalls to permit outbound FTP traffic.

Other Audit and Investigations Group Accomplishments

Internal improvements and processes:

- Initiated reviews and updates of six (6) existing Compliance Procedures (CPs), and two (2) Compliance Instructions (CIs). Created one (1) new CP for Technical Feasibility Exception (TFEs). Revisions were made to align with Compliance Monitoring Enforcement Program (CMEP), NERC Rules of Procedures (ROP), NERC Compliance Directives and Bulletins. CPs and CIs are applicable to Operations & Planning (O&P) audits (44 off-site and 5 on-site), and CIP audits (2 off-site and 11 on-site) scheduled for 2012, Self Certifications, Self Reports, Spot Checks, TFEs, Events Analysis, and Compliance Investigations. The revised CPs have been posted on NPCC's public Compliance website.
- The NERC Event Analysis Process (EAP) Phase II program only requires compliance self assessments for Category 2 and higher events (Category 1 being "Lower significance" and Category 5 being "High significance"). NPCC has successfully encouraged its registered entities to conduct self assessments or standards reviews for all existing 53 qualifying events (Category 1 and up) as well as future events as a demonstration of a strong culture of Reliability and Compliance. All qualifying events were reviewed to determine an added benefit in the production of valuable lessons learned for the industry which may not have occurred had a formal compliance investigation been required.
- NPCC has championed efforts in authoring and applying the Events Analysis interface with compliance as part of its representation on the NERC Event Analysis Working Group (EAWG). NPCC has demonstrated implementation of the interface within its region as an example for the other regions.
- Provided essential support for the NPCC Criteria Compliance Enforcement Program (CCEP). Coordinated CC member ballot and approval of the CCEP-1 process document and CCEP-2 Implementation Plan to formalize the program; retired Criteria A–8, Guide B-22, and Procedure C-22, which was formerly implemented by the CMAS group; developed secure FTP process for Full member submittal of thirty (30) Criteria Certification forms and five (5) UFLS Implementation Plan Status reports submitted by Reliability Coordinators and Balancing Authorities; developed a "CC Member Restricted Area" location on the NPCC website and posted the submittals there; developed thirty (30) unique password accounts and instructions so that each member of the Compliance Committee could securely access and review submittals for CC member approval; provided summary "scorecard" of the secure submittals in preparation for CC member review and approval; conducted "landmark" first implementation of CC member review and approval of 2010 Criteria Certification Form submittals; developed draft CC Report to RCC with summary and results of CC Member Review and Vote; coordinated CCEP Working Group meetings to review and develop 2011 blank CCEP submittal forms, address Directory 12 UFLS Implementation Plan Status Report forms which were unique for each RC/BA.
- Compliance staff performed extensive review of new NPCC website and extensive cleanup and transfer of audit reports, schedules, and other existing compliance documentation that was missing from the old NPCC website. Reviewed and identified other documentation with diverse owners containing anomalies so that other stakeholders could take action to rectify.

To improve consistency of audits and other Regional activities:

- Participated on numerous NERC Committees and Working Groups to discuss and develop approaches, answers and tools to address topical issues and attain consistency among Regional Entities, including:
  - ✓ development of Auditor Tools and Auditor Manual;
  - ✓ review and redrafting of NERC Process Directive for Regional Entity Compliance Audit Report Processing;
  - ✓ revisions to RSAWs to correlate to latest versions of NERC standards;
  - ✓ working with other Regions and NERC in developing Audit Approach documents for several reliability standards to employ a consistent approach to audits. These include MOD-001, MOD-004, MOD-008, MOD-030, COM-002, FAC-003, PRC-005 and PRC-023. Additional Audit Approach documents are being developed based on the Tier 1 Actively Monitored List of Standards;
  - ✓ development and approval of random sampling methodology (RAT-STATS);
  - ✓ Industry vote for interpretations for Actively Monitored Standards (COM-002);
  - ✓ development, implementation and presentation to other Regions and NERC, methods that promote efficiency and consistency in applying the requirements outlined in NERC Appendix 4D of the Rules of Procedure (CCWGT); and,
  - ✓ attendance at CIP Version 5, Standards Drafting Team Meetings to provide feedback on the audibility of the new standards and share problems and experiences in auditing to the existing versions of the standards.
- Industry Workshop presentations:

  2011 NPCC Spring and Fall Compliance Workshops

  Compliance staff prepared and presented the following:
  - ✓ Auditing CIP standards;
  - ✓ Technical Feasibility Exceptions (Spring and Fall, 2011);
  - ✓ 2011 Audit Program and O&P audit observations;
  - ✓ ERO Events Analysis Process;
  - ✓ CIP Audit Observations;
  - ✓ Protection System Mis-operation Reporting and Compliance;
  - ✓ Set up NPCC Outlook Mailbox Workshop-Questions@NPCC.org to solicit topical Questions from attendees. Provided answers to submitted questions and classroom questions during the Workshop's 3 classroom sessions; and,
  - ✓ Audit Evidence substance and style (enhancements using audio technology).

  2011 NERC ERO Auditor Spring and Fall Workshops
  - ✓ Panelist participation for PRC-005 compliance and sampling (Spring 2011); and,
  - ✓ NPCC developed and gave presentation on Audit Approach to NERC MOD standards (Fall 2011). Presentation is posted on NERC's website under the Compliance; Regional Programs; ERO Workshop tab (Item V-A).

  Association of State Dam Safety Officials, Annual Dam Safety Conference (Washington DC)
  - ✓ Physical Security SME prepared presentations on the topics of Physical Security and CIP challenges to the Hydropower Industry - topics covered included most violated CIP Standards, Physical and Cyber security of Hydropower facilities, preparation for audits and regional audit approach.
- Participated in NERC Webinars and reviewed documentation on directives, CANS, and review of FERC orders for impact on audit scope to maintain awareness of topical issues affecting compliance and audits. All NPCC auditors attended at least one of the two ERO Auditor Workshops.

- Performed three (3) offsite and one (1) onsite joint Regional Entity audits - two (2) as lead region and two (2) as support Regional Entity. Differences in practices were critiqued at NPCC auditor meetings to reinforce NPCC interview approach and specific data handling processes.
- Provided input to NERC as requested: 2011 Audit status reports, 2012 Audit Schedule, audit reports for NERC Key Reliability Standard Spot Check (KRSSC) Program.

Goals	Threshold	Target	Stretch	Weight
Goal #4 Training, Education & Operator Certification Program	Establish a Regionally consistent implementation of NERC Standard PER-005 requirements – by 9/11.	Attainment of Threshold Goal and: Incorporate all posted lessons learned from the NERC event analysis program in the NPCC operator training seminars by 11/11.	Attainment of Target Goal and: Develop a Regionally consistent, systematic approach to training to design, develop and administer system operator training programs – by 12/11.	5

Goal #4 Training, Education & Operator Certification Program

Assessment of Goal Attainment: The Target attainment level for Goal #4 was achieved (100% of Target level achieved). At the NPCC System Operator Seminars conducted during 2011, NPCC presentations on the Event Analysis Process included: reasons for and the expected benefits from the new Process; discussion of what took place during Phases I and II of the field trial; the categories of events to be reported; the stages of the reports that must be provided by industry entities to NERC and the Regional Entities; the timing and level of detail for the required reports; and, lessons learned.

Supporting Materials and Background

The CO-2 System Operator Training Working Group has devoted portions of each meeting since 2007 to the sharing of the approaches used to satisfy the most significant of the NERC PER-005-1 "System Personnel Training" standard requirements, including R1.1, R1.1.1 and R1.2, that are needed to implement a systematic approach to training. In addition the content of the NERC Continuing Education Program and the NERC Continuing Education Administration Manual provides details on how to interpret and satisfy the requirements in PER-005-1. The basic PER-005-1 requirements are:

- R1.1 Create a System Operator Task List—Separate out reliability and market-related tasks
- R1.1.1 Update the Task List
- R1.2 Design and Develop Learning Objectives and Training Material
- R1.3 Deliver Annual Training
- R1.4 Program Evaluation of Training
- R2 Verify each of its System Operator's capabilities to perform each assigned task
- R3 Provide 32 hours of emergency operations training

In 2011 the NPCC System Operator Training Working Group (CO-02) has completed much of the work associated with requirements R1.1, R1.2 involving job task identification and job task analysis in the NERC Reliability Standard PER-005-1, "System Personnel Training."

While the NPCC RC/BAs are using slightly different approaches to satisfy the requirements, the collaboration among the CO-2 Working Group members has led to a shared approach to implementation within NPCC. This is to provide consistency on how the PER-005 standard requirements are satisfied. Key items with this include: 1) the content and level of detail in the system operator reliability-related task and sub-tasks used; 2) the ways job task analysis is being done by each RC/BA; and 3) shared use of a Task-to-Training Matrix.

The sharing of procedures and details for assembling and maintaining these programs has proven to be valuable because it allowed each area to improve their program while not requiring complete restructuring. This allowed the NPCC Area Operations Training programs to be similar, while still completely "personalized" to each RC/BAs.

In addition, sharing the experience each RC/BA has had during NERC Compliance Audits is also valuable in ensuring the RC/BAs build and maintain their respective programs to achieve compliance with all NERC Standards containing training requirements with special attention devoted to particular NERC standards such as the COM-002-2 "Communications and Coordination" standard, which addresses 3-part communication.

The Spring 2011 67th NPCC System Operator Seminar was held in early May, 2011 in Halifax, Nova Scotia. The table top exercise was on a progressive sabotage scenario and in addition a communication exercise was conducted. Presentations included: Nova Scotia Tidal Generation, Eastern Interconnection Frequency Response, the NERC Event Analysis Process and NPCC's role in it, facility additions and changes, system events/disturbances and outlook for 2011 summer operating conditions. The NERC/Region Event Analysis Process topic involved: 1) reasons for and the expected benefits from the new Process, 2) discussion of what took place during Phase I of the field trial, 3) the status of Phase II of the field trial, including differences from Phase I, 4) the categories of events to be reported, 5) the stages of the reports that must be provided by industry entities to NERC and the Regions and 6) the timing and level of detail for the required reports and 7) lessons learned. Seminar participants received Continuing Education Hours and presentation content was used for the balancing authority area training programs.

The Fall 2011 68th NPCC System Operator Seminar was conducted in November, 2011 in Niagara Falls. The table top exercise was a multi-topic operating strategy session with sharing of different approaches to similar situations, in addition a brief three-part communication exercise was done. Neighboring PJM trainers attended and participated in the seminar. Presentations included: an overview of the operation of the Niagara River System, PJM System Operation and Operator Tools, NPCC Current Activities which included a review of Event Analysis Process lessons learned since the start of the process, facility additions and changes, system events/disturbances and outlook for 2011-2012 winter operating conditions. Seminar participants received Continuing Education Hours and presentation content was used for the Balancing Authority area training programs.

In addition, NERC has reinitiated the Training and Education Group (TEG) to coordinate the development of Regional Entity and NERC staff training and registered entity education materials to support and continually enhance reliability. NPCC is actively participating on the group.

Goals	Threshold	Target	Stretch	Weight
Goal #5 Situation Awareness Program	Establish a systematic and repeatable NPCC event analysis process consistent with the NERC event analysis effort, including root cause analysis and Standards review; approved by the RCC – by 12/11.	Attainment of Threshold Goal and: Establish an automated NPCC event analysis data base - by 12/11.	Attainment of Target Goal and: Develop an automated event recommendations tracking system to facilitate monitoring recommendations generated by event analyses through to their implementation – by 12/11.	10

Goal #5 Situation Awareness Program

Assessment of Goal Attainment: The Target attainment level for Goal #5 was achieved. In May of 2011, the NPCC Events Data Base was established. Working in collaboration with the SERC IT Staff, NPCC Staff expanded a SERC data management tool, its "Events Capture System," to automate the NPCC event analysis process. The NPCC Events Data Base automatically assigns an event identification number for each qualifying event entered, provides tracking status for each step of the NERC review from initial Situational Awareness through, if required, the development of a NERC Event Analysis Report. All documentation and correspondence relevant to each unique event is stored and is immediately accessible and retrievable for the event. At the September 8, 2011, meeting of the NPCC Reliability Coordinating Committee, the RCC endorsed NPCC Document EAI-01, "Conducting NERC ERO Event Analysis Process," defining the NPCC Event Analysis Process consistent with the NERC Event Analysis Process.

Supporting Materials and Background

Following significant NPCC staff involvement in the developmental efforts, NERC is finalizing its event analysis program, the ultimate goal of which is to serve as a broad learning initiative to more rapidly disseminate to the industry those lessons learned in the analysis of a system event from which the industry may profit through enhanced reliability. By integrating a "bottom-up" approach to a disturbance review within the framework of the event analysis program, consistency, comparability, flexibility and timeliness in the event analysis process will be promoted. During 2011, NPCC Staff assisted in the coordination of two field trials of the NERC Event Analysis process, soliciting and incorporating the comments and recommendations of the industry in a final draft process document submitted to the NERC Planning Committee and NERC Operating Committee at their respective meetings of December 13 and 14, 2011. The elements of this process are now being integrated into the NERC Rules of Procedure.

The manner in which the registered entities, NPCC and NERC evaluate and analyze system disturbances is critical to the understanding of the event and the gleaning of lessons to be learned to enhance operational performance, to prevent a similar event from reoccurring or to mitigate the future consequences of such an event. Effective event analysis must: identify as quickly as possible what happened; establish the sequence of events associated with the disturbance; realize the cause or causes of the event; implement corrective actions; and, disseminate recommendations and lessons to be learned to the industry.

In its implementation of the process, NPCC has established a team of staff members to provide outreach to the registered entities to facilitate their engagement in the event analysis process, to discuss disturbances as they occur, to guide the membership in the expectations of the process and

to answer any questions as they arise. An automated data base has also been established at NPCC to catalog events, reports and lessons learned and facilitate the monitoring of the effort by NPCC Staff.

Operational Awareness Tools

Reliability Indicators

NPCC has completed the first phase of the FERC-NERC-Regions situation awareness initiative, NERC Situational Awareness-FERC, NERC, Regions (SAFNR). At the request of the FERC, the Reliability Coordinator Areas have developed procedures to provide to the FERC detailed operating data for their respective footprints. The intent of the effort was to permit the FERC to measure the health of the Interconnections and to identify parameters which may warn of a developing crisis, thus precluding a major cascading event. To fulfill its portion of the first phase effort, NPCC implemented a geographically based visualization of selected reliability indicators. NPCC Staff and each Reliability Coordinator of NPCC has access to near real time displays depicting a geographic visualization of the complete NPCC footprint.

In 2011, NPCC staff actively supported NERC in its development of the second phase of the SAFNR effort, which will enhance the SAFNR visualization tool by providing more detailed line flow information and commonality across all Regions in the display formats.

Operating Tools

Integration of Wind Farms

The Working Group IST-2 is completing a review of the communications of operational telemetry to ensure that the security of such data can be maintained as the increased amounts of variable generation is added to the system.

System Restoration

Wide-Area Restoration Drill

The CO-11 Working Group organized an enhanced, wide area restoration drill among the Reliability Coordinators of NPCC and their neighboring Reliability Coordinator areas. The joint wide area restoration simulation among the Reliability Coordinators of NPCC, as well as their counterparts in the Midwest ISO and PJM, was conducted by the CO-11 Working Group CO-11 in October 2011.

In 2011, the NPCC Restoration Working Group (CO-11) developed new drafts of NPCC Regional Reliability Reference Directory No. 8, “System Restoration,” and former Type C Procedure NPCC Document C-35, "NPCC Inter-Area Power System Restoration Procedure."

High-Impact, Low Frequency (HILF) Event Risk Initiatives

In 2011, NPCC participated in five active NERC Task Forces formed to pursue the recommendations of the joint NERC and United States Department of Energy report, "High-Impact, Low-Frequency Event Risk to the North American Bulk Power System," released in June 2010.

NERC Geomagnetic Disturbance (GMD) Task Force

NPCC Members and members of the NPCC Task Force on Coordination of Operation have contributed in 2011 to the NERC Geomagnetic Disturbance Task Force, the draft report of which will be directed to the NERC Standing Committees for comment in January 2012.

NPCC has measures in-place to respond to GMD events, through the Geomagnetic Storm Mitigation System (GSMS) provided by the Solar Terrestrial Dispatch. The GSMS is a solar notification and communication system for the five Reliability Coordinators of NPCC. An active

communications software package installed on the system operator's console provides each of the NPCC Reliability Coordinators with geomagnetic storm alerts and the ongoing status of solar activity.

NERC Severe Impact Resilience Task Force

NPCC Members and members of the Task Force on Infrastructure Security and Technology have contributed in 2011 to the NERC Severe Impact Resilience Task Force, the draft report of which will be directed to the NERC Standing Committees for comment in January 2012.

NERC Spare Equipment Database Task Force

In 2011, NPCC staff participated in the development of the NERC Spare Equipment Database Task Force. NPCC staff will act as the Regional Entity Coordinator to help coordinate the Spare Equipment Database (SED) which is a NERC sponsored initiative to establish a listing of spare transmission equipment that require six months or more to manufacture. NERC registered Transmission Owners and Generator Owner are expected to voluntarily list their spare transformer and GSU equipment (100 kV and above) in a secure database format which can be used by entities faced with long-lead times to replace damaged equipment in the aftermath of a HILF events. NERC currently has a signed contract with Open Access Same Time Information Systems to deliver a web based tool by the second quarter of 2012.

NERC Smart Grid Task Force

Members of the Task Force on Infrastructure Security and Technology are contributing to the ongoing efforts of the NERC Smart Grid Task Force.

NERC Cyber Attack Task Force

Members of the Task Force on Infrastructure Security and Technology are contributing to the ongoing efforts of the NERC Cyber Attack Task Force.

System Preparedness

Weekly Conference Call

NPCC staff coordinated this weekly effort which helps to ensure electric system reliability. Timely summary reports were issued to operations staff throughout NPCC and to PJM and Midwest ISO for all 52 weeks of 2011. These calls and summary reports have taken place and have been issued without exception for at least the last 13 years.

NPCC staff continues to pursue possible options to automate the data entry process on the part of the Reliability Coordinators.

Daily Conference Call

Each morning, the NPCC Reliability Coordinator control rooms, as well as the RCs for MISO and PJM, take part in a regularly scheduled conference call to enhance system situational awareness. The goal of this call is to alert all neighboring Reliability Coordinators of any potential emerging problems which could lead to reliability concerns in the course of the day's operations. Subjects for discussion are limited to credible events which could impact the ability of a Reliability Coordinator to serve its load and meet its operating reserve obligations, or which would impose a burden to the neighboring NPCC Reliability Coordinators or the Eastern Interconnection.

Emergency Preparedness Conference Call

Three emergency preparedness calls were held during the week of July 20-22, 2011when a heat wave resulted in very heavy demands throughout the U. S. Midwest, northeastern U. S. and

eastern Canada. ISO-New England and NYISO all-time would have been exceeded during that period except that large amounts of demand response were used to provide load relief.

Six emergency preparedness calls were held prior to and during Hurricane Irene during the August 25-29, 2011 period. These calls enhanced system situational awareness and provided great assistance in planning operations during the coming day or hours among the NPCC Reliability Coordinators, PJM, and the Midwest ISO. NPCC staff coordinated the calls and issued notes.

NPCC Staff also participated in the RRO-NERC-Regulatory conference calls which were held during Hurricane Irene and Winter Storm Alfred.

Emergency Telecommunications Coordination

NPCC staff, working with the Reliability Coordinators and the IST-2 Working Group (IST-2) determined that voice communications were adequate for emergencies, as all Areas had at least both primary and backup voice communication systems. The monthly tests from November 2010 to October 2011 have shown that the Iridium satellite communications to/from ISO-NE, NYISO, IESO, NBSO and TransEnergie were successful.

The NPCC System Operations Managers Working Group (CO-08) has revised and updated NPCC Regional Reliability Reference Directory 1, "Design and Operation of the Bulk Power System."

NERC Alerts

For each NERC Alert, NPCC staff and the Task Force on Infrastructure Security and Technology actively coordinates a review among the NPCC Members of their understanding of the implications of the Alert and their expected response. In 2011, two NERC Alerts received particular focus:

Facility Ratings

The NERC Alert addressing facility ratings, “Consideration of Actual Field Conditions in Determination of Facility Ratings,” was issued by NERC on October 7, 2010, recommending that Transmission Owners (TOs) and Generator Owners (GOs) verify that the methodology used to determine the facility ratings associated with overhead transmission is based on actual field conditions. The NERC proposed a time frame of three years to conclude the effort, with priority given to facilities deemed High Priority, Medium Priority and Low Priority. The registered entities were asked to designate the three prioritization categories into which their facilities would be assigned together with their plan for meeting the NERC timeframe. High Priority facilities would be reviewed in calendar year 2011, Medium Priority facilities would be reviewed in calendar year 2012 and Low Priority facilities would be reviewed in calendar year 2013. The Regions were charged to assess the plans of the entities and to monitor the response of the industry to the Alert, and NPCC has actively worked with its registered entities in this undertaking.

NPCC staff verified that all 167 of the registered TOs and GOs in NPCC replied to the Alert in a timely manner. Through early June, NPCC Staff had reviewed, and discussed with the entities, all of their responses to the Alert. Based on the revised criteria issued by the NERC on April 26, 2011 (providing criteria through which certain entities may be excluded from the Alert), eleven GOs continued to be monitored by NPCC. Among the Transmission Owners, twenty-three entities continue to be monitored. All of the plans were judged acceptable. As part of this tracking, NPCC provided to NERC a status report of these thirty-four ongoing facility reviews

on July 15th; a year end summary will have been provided on January 15th, and such status reports will be provided until the conclusion of the effort at the end of calendar year 2013.

To date, twenty discrepancies resulting in facility deratings have been identified by field inspections, of which ten have already been mitigated; ten deratings remain in effect.

AURORA

NPCC Members reviewed the two update requests from NERC in response to the ongoing AURORA Alert, "AURORA Mitigation-Protection and Control Engineering Practices and Electronic and Physical Security Mitigation Measures." NERC will continue to monitor the industry response to the Alert to its completion.

Goals	Threshold	Target	Stretch	Weight
Goal #6a. Reliability Assessment & Performance Analysis Program	Provide active NPCC participation in NERC Revision the Definition of the Bulk Electric System initial draft BES definition – by 5/11	Attainment of Threshold Goal and: BES definition, exception criteria and Rules of Procedure exception process developed, consistent with NPCC input – by 12/11	Attainment of Target Goal and: Achieve NPCC objectives of : "intelligent bright line", technically based exception process, and transitional implementation period in NERC BOT approval of related BES filings – by12/11	15

Goal #6a Reliability Assessment & Performance Analysis Program

Assessment of Goal Attainment: The Stretch attainment level for Goal #6a was achieved. Ballots for the Definition of Bulk Electric System and associated implementation plan, and for the application form titled 'Detailed Information to Support an Exception Request' referenced in the Rules of Procedure Exception Process concluded on November 21, 2011, both with a weighted segment approval of over 81%. Because of timing issues around the December holidays, the NERC BOT consideration was ultimately scheduled for January 18, 2012, in advance of the January 25, 2012 filing deadline.

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Supporting Materials and Background

In Order 743, the Federal Energy Regulatory Commission (FERC) directed NERC, through their Reliability Standards Development Process, to revise the definition of the Bulk Electric System (BES) to improve clarity, reduce ambiguity, establish consistency across all Regional Entities within the U.S., and ensure that the definition encompasses all facilities necessary for operating an interconnected electric transmission network.

Pursuant to the Final Rule, NPCC staff has actively participated in every face-to-face meeting and teleconference of the NERC Standards Drafting Team formed to review the definition of the BES and corresponding changes to the NERC Rules of Procedure (RoP). NPCC staff was asked to assist in the conduct of two NERC sponsored BES Webinars; over 800 industry representatives participated in those Webinars.

NPCC staff provided timely updates to the NPCC Board through written meeting summaries and Board presentations. In addition, NPCC staff provided presentations on the subject at the 2011 Spring and Fall Compliance and Standards Workshop, and at the 2011 NPCC General Meeting.

The following BES Project milestones were met:

- BES Standard Authorization Request Finalization - posted December 17, 2010 - January 21, 2011
- Initial Draft of BES Definition – posted May 11 – June 10, 2011
- Complete Formal Comment & Ballot – posted September 30 – October 10, 2011
- Recirculation Ballot – posted November 10 – November 21, 2011
- BES filing – submitted for NERC BOT consideration scheduled for January 18, 2012

Two recirculation ballots, one for the Definition of Bulk Electric System and associated implementation plan, and one for the application form titled 'Detailed Information to Support an Exception Request' referenced in the Rules of Procedure Exception Process concluded on November 21, 2011.

Both recirculation ballots achieved stakeholder approval. The ballot for definition of BES achieved a quorum of 95.92% and a weighted segment approval of 81.32%. The ballot for the application form titles 'Detailed Information to Support an Exception Request' achieved a quorum of 93.02% and a weighted segment approval of 81.48%. 113 sets of comments, including comments from more than 75 different people from approximately 45 companies representing eight of the 10 Industry Segments were considered and addressed.

NPCC staff was instrumental in achieving the following NPCC Board of Directors BES policy input during its extensive deliberations with the BES Drafting Team:

- moving the development of a BES Exception Process Criteria from the Rules of Procedure Team to the BES Drafting Team;
- posting of a draft BES Exception Process Criteria for parallel review with the 1st Draft BES Definition for industry comment;
- development of a BES Exception Process Criteria that allows for the exclusion of distribution facilities as identified through the application of appropriate criteria, such as those contained in the FERC 7 Factor Test;
- the concurrent second postings of the BES definition and the BES Technical Principles for Demonstrating BES Exceptions with the consideration of comments received;
- a BES Definition and Technical Principles for demonstrating BES Exceptions that respects the statutory limits imposed under FPA 215 to not include facilities used in the local distribution of electric energy as established by applicable regulatory authorities; and,
- consistency between the BES definition and the Compliance Registry criteria.

The NPCC Board also acknowledged that the developed NERC BES Definition was responsive to the directives of the FERC Order. The NPCC objectives to achieve an "intelligent bright line, a technically based exception process, and a transitional implementation period, consistent with the expectations of the Final Rule were met.

BES Exception Process – revision to NERC Rules of Procedure

NPCC staff and through its consultant representative worked to develop a BES exemption process that includes clear, objective, transparent, and uniformly applicable procedure for the exemption (exclusion/inclusion) of BES facilities from the 'bright-line' BES definition. In order to avoid an inconsistent application of the exemption process, NERC will oversee the exemption process executed by the Regional Entities in order to ensure an objective and uniform application.

Concurrent with the development of the revised Bulk Electric System definition, a Bulk Electric System Rules of Procedure Team ("BES RoP Team") was formed to develop a procedure for processing exceptions to the Bulk Electric System definition. The BES RoP team developed a second draft of the proposed Appendix 5C Bulk Electric System Component Exception Procedure, which was posted along with several related documents for comment for 45 days (from September 13, 2011 through October 27, 2011).

NPCC has worked extensively with the BES RoP Team, in order to shape the BES exception proposals to be consistent with the expectations of the Final Rules, and NPCC policy direction.

NPCC BES Transition/Implementation Plans

FERC directed NERC to work with the Regional Entities affected by the Final Rule to submit for Commission approval transition plans that allow a reasonable period of time for the affected entities within each region to achieve compliance with respect to facilities that are subject to Commission-approved Reliability Standards for the first time based on a revised bulk electric system definition. The Commission stated that it expects that NPCC is the only region that will be significantly affected. FERC directed NERC to file the proposed transition plans within one year of the effective date of the Final Rule.

NPCC is currently in the process of coordinating the review of NPCC transition plans through the NPCC Compliance Committee.

Goals	**Threshold**	**Target**	**Stretch**	**Weight**
Goal #6b. Reliability Assessment & Performance Analysis Program	Simulate and analyze potential mitigation measures (a/k/a Task 5 of the August 14, 2003 Northeast Blackout Study Plan) and obtain Task Force approval – by 12/11. Establish the technical parameters for a secure and reliable NPCC region wide program for the sharing of operating reserve for approval by the TFCO – by 8/11.	Attainment of Threshold Goal and: Develop recommendations based on mitigation measures study results and obtain RCC approval of study report – by 11/11. Develop a process to evaluate reliability impacts of participation in an NPCC regional reserve sharing program for RCC approval – by 12/11.	Attainment of Target Goal and: Coordinate mitigation measures study results and recommendations with the New York State reliability Council Defensive Strategies Working Group – by 12/11. Achieve RCC approval of ballot posting directory governing an NPCC Reserve Sharing program – by 12/11.	10

Goal #6b Reliability Assessment & Performance Analysis Program

Assessment of Goal Attainment: The Target attainment level for Goal #6.b. was achieved. At its November 29, 2011 meeting, the RCC unanimously approved the SS-38 Task 5 Study Report's assessment of potential measures that may prevent or mitigate the impact of major system disturbances originating from a wide range of initiating events. A proposed draft of the new NPCC Regional Reliability Reference Directory No. 6, "Reserve Sharing Groups," was finalized at the meeting of the NPCC TFCO held in August, 2011, and subsequently posted for public comment.

Supporting Materials and Background

At its November 29, 2011 meeting, the RCC unanimously approved the SS-38 Task 5 Study Report. This study effort completed the final task of the 2003 Blackout Study in the assessment of potential measures that may prevent or mitigate the impact of major system disturbances originating from a wide range of initiating events. NPCC members should benefit from the information that Task 5 study results provided. Task 5 study results have also been closely coordinated with the NYISO and the NYSRC who have also been conducting the New York Controlled Separation Study funded through a DOE grant.

A proposed draft of the new NPCC Regional Reliability Reference Directory No. 6, "Reserve Sharing Groups," was finalized at the meeting of the NPCC Task Force on Coordination of Operation (TFCO) held on August 11 and 12, 2011, and subsequently posted for public comment. The document established the framework for the reliable implementation of the sharing of operating reserve within NPCC, supplanting the original Type C Procedure C-38, "Procedure for Operating Reserve Assistance." The comments to the first posting have been reviewed by the TFCO, and, following a response to the comments, the document will be submitted to the NPCC Reliability Coordinating Committee (RCC), seeking approval for ballot. The draft includes the requirement for the quantification of the change in the reliability risk associated with a proposed reserve sharing agreement to be presented to the TFCO.

Following its approval, the new Directory No. 6 will also serve as the core of a new Regional Standard to be developed by the Task Force on Coordination of Operation.

Model Development and Improvement

Develop the MMWG 2011 library of power flow and dynamic models in accordance with the approved schedule and initiate efforts to improve the accuracy of the models. Enhance regional procedures for validation of data used in power flow and dynamic simulations and benchmark against actual system performance

NPCC staff participated in the ERAG, NERC and MMWG efforts to improve the accuracy of Wide-Area regional transmission models utilized in long-term and event analysis. The MMWG 2011 library of power flow and dynamic models was completed in accordance with the approved schedule. NPCC staff also participated in the NERC Eastern Interconnection frequency study to analyze generator governor response to frequency excursions.

NPCC staff participated in the NERC Model Validation Task Force's (MVTF) effort in developing procedures to be used to validate both power flow and dynamics models used in base cases. A field test for these procedures will be carried out in 2012. The MVTF are also looking at ways to improve Powerflow Solution Algorithms.

NPCC staff researched papers and past industry effort that went into the development of improved load modeling. The information obtained is critical in helping jump start the planned 2012 NPCC effort to address the remaining recommendation from the 2003 Blackout Study to develop an industry guideline for load modeling.

Review 2011 summer base case frequency response to ensure it correlates with unit commitment, complete the survey of NPCC governor response, and develop a white paper that identifies NPCC Guidelines for load modeling in transmission system analyses

NPCC staff activity contributed to the efforts of the ERAG Management Committee and Multi-regional Modeling Working Group, are working jointly with NERC, on a testing proposal to examine the modeling of overall Eastern Interconnection frequency response. The testing is intended to help assess changes in modeling needed to improve correlation of simulated

frequency response with actual events before going through the full process of establishing better models unit by unit (i.e. going to generating plants and evaluating operation and running system tests).

The testing consisted of: 1) disabling all existing governor models, 2) developing a set of scenarios of fully responsive on-line generator governor frequency response (e.g. 30%, 20%, 10%), 3) for each scenario, insert generic governor models into the study case for the designated percentage of capacity in each category, 4) observe system response in the simulations and compare to observed governor response for system events that involve capacity or load loss with system frequency impacts, 5) assess which scenario(s) best match the Eastern Interconnection frequency response from actual events.

The first sets of tests were done in October and results are currently being evaluated.

Provide leadership for NPCC-RFC Activities

NPCC staff acted as the Chair of the RFC-NPCC Inter-regional Working Group, and planned, organized and direct this engineering group in conducting and producing the summer and winter period inter-regional transmission capability assessments. This year's winter period study was replaced by an assessment of the 2020 summer period.

The Eastern Interconnection Reliability Assessment Group's SERC east-RFC-NPCC Working Group and Steering Committee's 2011 summer and 2020 summer RFC-NPCC Assessment Reports were completed and issued on schedule.

In 2011, NPCC staff participated in the development of the ERAG Combined Study Procedure Manual.

Technical Support of NPCC Reliability Criteria Development

Provide technical input to the Open Process Review of NPCC Directory No. 1

NPCC completed a comprehensive CP-11 Working Group review of the NPCC Directory No.1, Design and Operation of the Bulk Power System, to assure that it is consistent with other NPCC Directories, Criteria, Guidelines and Procedures and with applicable NERC Reliability Standards, and a rewrite of criteria requirements into more specific and measureable requirements to support the NPCC Criteria Compliance Enforcement Program. The draft revised Directory No. 1 with its phase 2 criteria requirement conversion has been submitted to the Task Forces for their final review and endorsement prior to posting it in the NPCC Open Process Review.

Support Phase 2 of the NPCC Directory Project

A revised and enhanced NPCC Regional Reliability Reference Directory 5, "Reserve," clarifying the implementation of Simultaneous Activation of Ten Minute Reserve (SAR) following a radial source contingency, was developed during 2011 and has been posted for public comment.

NPCC staff led several Task Forces in completing a comprehensive review of Directory No. 7, Special Protection System Criteria. Draft revised Directory No. 7 is expected to be posted in Open Process Review in early 2012.

The NPCC Task Force on Coordination of Operation revised NPCC Regional Reliability Reference Directory No. 9, "Verification of Generator Gross and Net Real Power Capability," and NPCC Regional Reliability Reference Directory No. 10, "Verification of Generator Gross and Net Reactive Power Capability" were approved by the RCC at its November 29, 2011 meeting.

On December 28, 2011 NPCC Membership approved the revised versions of NPCC Regional Reliability Directories Nos. 9 and 10.

Reliability and Adequacy Assessments

Complete the NPCC Tie Benefits Analysis

The NPCC Task Force on Coordination of Planning reviewed the "*Review of Interconnection Assistance Reliability Benefits"* report at its May 11, 2011 meeting and agreed with its main conclusions:

- that the methodology and assumptions used in this Review were consistently applied to all NPCC Areas, using the same multi-Area reliability model,
- that the NPCC Area estimates of the interconnection benefits used to meet the NPCC Resource Reliability Criterion were reviewed on a consistent basis; and,
- that the interconnection assistance values reported by the NPCC Areas in their recent resource adequacy assessments appear to be reasonable and do not overstate interconnection benefits.

The RCC approved the report at its meeting on June 1, 2011.

Conduct the 2011 NPCC Multi-area Probabilistic Long-Range Adequacy Overview

Due to the delay in the approval of the NERC 2011 Long-Term Reliability Assessment (LTRA) on which it is based, the 2011 NPCC Long Range Adequacy Overview will be presented to the RCC for review and approval at its March 2012 meeting, following NPCC's Task Force on Coordination of Planning review.

The Overview evaluates the near term and long-range (five year) adequacy of NPCC Areas, reflecting neighboring regional plans proposed to meet their respective resource adequacy planning criteria, including estimates of probabilistic metrics approved by the NERC Planning Committee for consideration in future NERC Long-Term Reliability Assessments.

Conduct the NPCC 2011 Summer and 2011/2012 Winter NPCC Reliability Assessments, and obtain TFCO and RCC approvals

The CO-12 Working Group completed and issued the NPCC 2011 summer and 2011/2012 winter NPCC Reliability Assessment Reports. The CP-8 Working Group's Multi-Area Probabilistic simulation results and report documentation were included in the NPCC Reliability Assessment Reports. Presentations providing the results of the assessments were provided to the Task Force on Coordination of Operation at their February and October meetings and to the Reliability Coordinating Committee at their November 29, 2011 meeting.

Coordinate NPCC area input and report review associated with the NERC 2011 Long-Term Reliability Assessment (LTRA), including NERC Scenario Analysis, and NERC pre&post Seasonal Assessments

The NERC Reliability Assessment Subcommittee (RAS) 2011 summer and 2011/2012 winter draft LTRA and data were all provided to NERC on time; all NERC RAS peer review comments were addressed and questions answered to finalize the NPCC input to the RAS reports. The LTRA report included a section that updates NERC's "*2010 Special Reliability Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*."

The 2010/2011 winter and 2011 summer post assessment NERC assessment and data were provided to NERC on schedule. In addition, NPCC input was provided for the NERC "*2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power*

Interdependency in the United States", which reviews gas and electric interdependencies, assesses existing and future challenges, identifies areas of vulnerability, and provides recommendations for enhancing reliability. This NERC Special Reliability Assessment was approved by the NERC Planning Committee and BOT and released in December, 2011.

Review and Analyze NPCC Protection System Mis-operations

NPCC staff, in coordination the NPCC Compliance Committee, and the Task Force on System Protection, addressed the significant challenge regarding protection system mis-operations identified by NERC as the number one reliability concern in the Industry. Through extensive effort by Staff and NPCC members, both technical (C-45) and compliance (CP-7) procedures were established in NPCC for reporting and reviewing specified protection mis-operations on a quarterly basis in a consistent format. All quarterly reported mis-operations are being reviewed by the NPCC SP-7 Working Group and reported by Staff to the RCC and to NERC. Trending and performance metric are being established to address this reliability concern.

NPCC staff participated in the ERO-RAPA initiative to assess the application of Special Protection System (SPS) among the eight Regions. This extraordinary effort is expected to lead eventually to the development of a common set of requirements and definition for SPS and revisions to the existing NERC standard.

Reliability Metrics

Developed the "*NERC RIS Probabilistic Assessment for the NPCC Region***"** report for the NERC Resource Issues Subcommittee (now part of the Reliability Assessment Subcommittee) that provides the requested probabilistic reliability metrics and documents the assumptions and approaches used to implement the methodology within NPCC, as a trial for inclusion in future NERC Long Term Reliability Assessments. In addition, a comparison of NPCC's 2010 and 2011 NPCC Long Range Adequacy Overview results of the hourly Loss of Load Expectation (LOLE) and annual Expected Unserved Energy (EUE) probabilistic metrics covering the requested future five-year period was given at the NERC LOLE Best Practices Working Group in November 2011.

NPCC staff actively participated in the ERO-RAPA Group's activities related to NERC data collection requests in support of developing NERC Reliability Metrics, including:

- ✓ Consistent Regional reporting of Relay Mis-operations
- ✓ Regional support of NERC TADS, and the start-up of DADS, GADS, and the SED
- ✓ Documenting Underfrequency Loadshedding operation
- ✓ Identifying Operating Procedures assumed in conduct of TPL studies
- ✓ Classification and number of Special Protection Systems
- ✓ Monitoring voltages at critical system locations

As the 2011 NPCC Transmission Availability Data System (TADS) Regional Coordinator, NPCC staff reviewed all required data entry related to transmission line and equipment outages recorded in the NERC WebTADS Information System, and provided oversight of the NERC TADSTF activities. NPCC staff reviewed accuracy of the TADS database with respect to NERC PRC and ALR standards.

As the 2011 NPCC Demand Response Availability Data System (DADS) Regional Coordinator, NPCC staff assisted member reporting entities in preparation for required data entry related to demand response recorded in the NERC WebDADS Information System, and provided oversight of the NERC DADSTF and DADSWG activities.

As the 2011 NPCC Generating Availability Data System (GADS) Regional Coordinator, NPCC staff providing oversight for member reporting entities and designated reporting entities in advance of beginning of mandatory GADS reporting period.

Additional Achievements

NPCC staff, in conjunction with SS-38, TFSS, and the RCC, completed the comprehensive review and approval of proposed set point changes submitted by owners of nuclear generating units with motor-generator set with effective threshold settings greater than allowable by the NPCC UFLS program.

NPCC staff also provided expertise and its Criteria A-10, Classification of Bulk Power System Elements as a model in the NERC development of a screening test within the Data Request expected to be implemented in early 2012 to address FERC Order 754 related to single point of failure of protection systems at significant impact facilities in system planning studies.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

John Q. Anderson, Chair
NERC Board of Trustees

January 17, 2012

Mr. Scott Helyer, Chair Elect
NERC Member Representatives Committee
Vice President, Transmission
Tenaska, Inc.
1701 E. Lamar Blvd.
Arlington, Texas 76006

Re: Policy Input to NERC Board of Trustees

Dear Scott:

First, congratulations for being elected to lead the Member Representatives Committee (MRC) in 2012. Bill Gallagher did an outstanding job, so you have a tough act to follow.

After carefully reviewing the agenda for the February 8, 2012 MRC meeting, I would appreciate receiving policy input from the committee members on the following activities, priorities, or other areas of interest:

Update on ERO Enterprise Strategic Planning – Following the November Board of Trustees (Board) meeting, NERC and the Regional Entities rededicated efforts to coordinate a collaborative network, the ERO Enterprise, that brings together their collective leadership, experience, judgment, skills, technology, and duly delegated statutory responsibilities for the purpose of ensuring the reliability of the bulk power system (BPS). As the strategic planning of the ERO Enterprise continues into the New Year, the Board would welcome feedback on how to best identify priority areas of interest, common objectives and responsible business practices. Gerry Cauley will review 2011 performance with the Corporate Governance and Human Resources Committee (CGHRC) at its meeting on February 8, 2012, and plans to present proposed 2012 goals for Board approval at its February 9 meeting. The Board welcomes MRC input on these 2012 goals, as well as longer-term strategic directions for the ERO Enterprise, by way of written policy input as well as open discussion at the MRC meeting on February 8.

Find, Fix, Track, and Report Initiative – NERC and the Regional Entities continue to employ a comprehensive and integrated risk control strategy that differentiates and addresses compliance issues according to their significance to the reliability of the BPS. As NERC and the Regional Entities increase their enforcement discretion in the implementation of compliance and enforcement activities, the Board is interested in hearing the committee members' perspective on the implementation of the Find, Fix, Track, and Report (FFT) process. Your input will also assist NERC in preparation for its six month status report to the Federal Energy Regulatory Commission.

Generator Operator (GO)/Transmission Operator (TO) Issues – NERC has suspended work on the entity registration guidance directive intended to clarify those standards and requirements applicable to GO/GOPs that would be registered as TO/TOPs. NERC will consider the following two outcomes prior to making any further decision to resume work on compliance guidance for the GO/TO initiative:

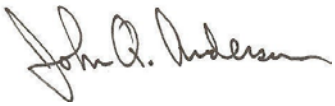
1) Guidance from the Board on the proposed revision of FAC-001, FAC-003 and PRC-004 (Standards Project 2010-07).
2) The final FERC approval of the NERC compliance filing concerning the upheld registry of Cedar Creek and Milford Wind as TO/TOP with appropriately scoped applicable standards.

The Board is particularly interested in policy input on the standards being presented for approval at its February 8 meeting, as well as any comments on the overall issue.

Rules of Procedure Changes — The Board would like to hear of any concerns the committee has with the general direction of the proposed substantive changes to the Rules of Procedure that the Board will consider for approval at its meeting on February 8. Are these changes, to date, effectively addressing the issues raised during previous MRC and Board meetings?

Thank you in advance for providing written comments to Dave Nevius, MRC secretary (dave.nevius@nerc.net) and Holly Mann (holly.mann@nerc.net) **by January 30, 2012** so they can be packaged and sent to the Board members in advance of the meeting.

Thank you,



John Q. Anderson, Chair
NERC Board of Trustees

cc: NERC Board of Trustees
Member Representatives Committee
Regional Executives

NPCC, Inc.

Report by the Treasurer

February 1, 2012

Board of Directors Meeting

NPCC, Inc.

Report Items:

- 2011 Year End Results
- Finance and Audit Committee Activities

NPCC, Inc.

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

January 20, 2012

North American Electric Reliability Corporation
3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
Attention: Mr. Michael Walker

Subject: NPCC Regional Entity Division Variance Comparison and Fourth Quarter 2011 Statement of Activities

Dear Michael:

The variance comparison for the period ended December 31st, 2011 is included along with Northeast Power Coordinating Council, Inc.'s unaudited 4th Quarter 2011 Statement of Activities.

Please do not hesitate to contact me via email at jhala@npcc.org or via telephone at (212) 840-1070 should you have any comments or questions with regard to the materials provided.

Sincerely,

Jessica Hala

Jessica Hala
Senior Financial Analyst

JH: jh
Enclosures

cc: Mr. Christopher Weir, CPA – NPCC Treasurer
Mr. Edward A. Schwerdt – NPCC President & CEO
Ms. Jennifer Budd Mattiello – NPCC Vice President & COO
ERO Finance Group

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

NPCC Regional Entity Division
Budget to Actual
Variance Comparison as of December 31, 2011

INCOME

- **Penalty Sanctions** (Actual income of $308,500 remitted to NPCC as of June 30, 2010 has been applied to reduce 2011 assessments to NPCC U.S. load serving entity designees.) All penalty sanctions remitted from July 1, 2010 through June 30, 2011 will be applied to reduce 2012 assessments to NPCC U.S. load serving entity designees and will be included in the NPCC 2012 Business Plan and Budget.

- **Workshops** (Actual variance of $53k under budget at year end)
  Actual fees charged per person for attending NPCC's standards and compliance workshops were less than originally budgeted.

- **Interest Income** (Actual income of $21k not included in budget)
  NPCC has not budgeted for interest income as returns on U.S. treasury securities fund are non-existent and corporate money market fund returns for 2011 were minimal for operating fund investment.

    - NPCC allocated $21k as a portion of total interest income (92%) to the Regional Entity Division consistent with the ratio of Regional Entity (RE) to Criteria Services (CS) Division 2011 funding. A common system of accounts, with divisional separation, is used for both RE and CS revenue tracking and financial reporting.

EXPENSES

- **Personnel Expenses** (Actual variance of $903k under budget at year end)
    - Recruiting knowledge-based professionals continues to be challenging. NPCC experienced two vacancies during the year from staff departures resulting in unanticipated budget underspend. Additionally, two positions budgeted for the full year in 2011 were not filled until late in the year. As a part of NPCC's succession initiative strategy, several of the 2011 new hires have been less tenured than budgeted for, which also yielded some budget underspend. In the benefits area, a significant number of professionals retained over the past four years continue to waive health insurance coverage, keeping superior coverage available to them from a prior employer. NPCC continues to budget for its full staff's health insurance coverage.

- **Meetings and Conference Calls** (Actual variance of $106k under budget at year end)
    - Continued efforts to hold more meetings onsite or via webinars have kept meeting and conference call expenses under budget. However, travel expenses exceeded budget year-to-date, primarily due to travel associated with compliance audits and on-site Technical Feasibility Exception reviews.

- **Contracts & Consultants** (Actual variance of $729k under budget at year end)
  - NPCC continues to judiciously utilize contractor and consultant services to complement staff functions. In addition, consulting fees associated with website, compliance portal, and software development budgeted under Contracts & Consultants were capitalized in accordance with NPCC capitalization policies and GAAP guidelines.

- **Office Costs** (Actual variance of $128k under budget at year end)
  - Computer equipment and leases budgeted within office costs were capitalized in accordance with NPCC capitalization policies and GAAP guidelines.

- **Miscellaneous** (Actual variance of $19k under budget at year end)
  - Employees training and education expenses were less than budgeted due to scheduling conflicts resulting from workload requirements.

FIXED ASSETS

- **Computer & Software CapEx** (Actual variance of $138k over budget at year end)
  - Acquisition of server software in the third quarter and software development costs in the fourth quarter of 2011.

- **Furniture & Fixtures CapEx** (Actual variance of $21k under budget at year end)
  - NPCC made no furniture & fixtures acquisitions in 2011.

- **Equipment CapEx** (Actual variance of $10k under budget at year end)
  - Actual Equipment Cap Ex of $18k represents acquisition of computer equipment for new employees in 2011.

- **Leasehold Improvements** (Actual variance of $14k under budget at year end)
  - NPCC made no leasehold improvements in 2011.

(Unaudited)
Submitted January 20th, 2012

Northeast Power Coordinating Council, Inc. - Regional Entity Division
Statement of Activities, Fixed Assets and Change in Working Capital
(Unaudited)

	2011 YTD Actual	2011 YTD Budget	2011 YTD Actual Variance from Budget	%
Funding				
Assessments	12,652,610	12,652,610	-	
Penalties	308,500	308,500	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	67,200	120,000	(52,800)	
Interest	20,694	-	20,694	
Miscellaneous	-	-	-	
Total Funding	13,049,004	13,081,110	(32,106)	-0.25%
Expenses				
Personnel Expenses				
Salaries	4,361,224	5,055,070	(693,846)	
Payroll Taxes	277,841	291,508	(13,667)	
Employee Benefits	973,785	1,134,918	(161,133)	
Savings & Retirement	791,099	825,301	(34,202)	
Total Personnel Expenses	6,403,949	7,306,797	(902,848)	-12.36%
Meeting Expenses				
Meetings	215,520	269,325	(53,805)	
Travel	872,965	668,000	204,965	
Conference Calls	51,729	96,571	(44,842)	
Total Meeting Expenses	1,140,214	1,033,896	106,318	10.28%
Operating Expenses				
Consultants and Contracts	1,526,367	2,255,047	(728,680)	
Rent & Improvements	621,276	626,127	(4,851)	
Office Costs	355,346	483,434	(128,088)	
Professional Services	880,336	892,751	(12,415)	
Miscellaneous	37,074	55,450	(18,376)	
Depreciation	180,799	138,626	42,173	
Total Operating Expenses	3,601,198	4,451,435	(850,237)	-19.10%
Other Non-Operating Expenses	-	-	-	n/a
Total Expenses	11,145,361	12,792,128	(1,646,767)	-12.87%
Net Change in Assets	**1,903,643**	**288,982**	**1,614,661**	**558.74%**
Fixed Assets				
Depreciation	(180,799)	(138,626)	(42,173)	
Computer & Software CapEx	138,341	-	138,341	
Furniture & Fixtures CapEx	-	20,886	(20,886)	
Equipment CapEx	18,549	28,557	(10,008)	
Leasehold Improvements	-	13,863	(13,863)	
Incr(Dec) in Fixed Assets	**(23,909)**	**(75,320)**	**51,411**	**-68.26%**
Total Budget (Expenses plus Incr(Dec) in Fixed Assets)	**11,121,452**	**12,716,808**	**(1,595,356)**	**-12.55%**
Change in Working Capital (Total Funding less Total	**1,927,552**	**364,302**	**1,563,250**	**429.11%**
Full Time Employees	31.42	31.42	-	
Headcount	32.00	32.00	-	
Beginning WC - 1/1/11	3,664,561	3,664,561	-	
Change to WC - 2011	1,927,552	364,302	1,563,250	
Working Capital at 12/31/11	**5,592,113**	**4,028,863**	**1,563,250**	

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. PA12-10-000
October 28, 2011

Northeast Power Coordinating Council, Inc.
Attention: Mr. Edward A. Schwerdt
President and Chief Executive Officer
1040 Avenue of the Americas, 10th Floor
New York, NY 10018

Dear Mr. Schwerdt:

The Division of Audits (DA) in the Office of Enforcement (OE) of the Federal Energy Regulatory Commission (the Commission) is commencing an audit of the Northeast Power Coordinating Council (NPCC). This audit will address NPCC's responsibilities and performance as a Regional Entity, including its performance pursuant to (1) the Delegation Agreement between the North American Electric Reliability Corporation and NPCC, (2) the NPCC Bylaws, and (3) other obligations and responsibilities as approved by the Commission. Additionally, the audit will evaluate NPCC's budget formulation, administration, execution, and resources used to achieve program results. This audit will cover the period from August 23, 2006 to the present.

This audit is being conducted pursuant to section 215 of the Federal Power Act, 16 U.S.C. § 824o (2006). Documents and information obtained by the Commission staff during the audit, as well as all working papers developed, will be placed in non-public files. Section 39.2(d) of the Commission's regulations, 18 CFR § 39.2(d) (2011), provides that each Regional Entity shall provide the Commission such information as is necessary to implement section 215 of the Federal Power Act.

NPCC must preserve and retain all existing and future records relevant to this audit. For purposes of this compliance audit, OE considers all relevant records to be all documents and communications (including emails, instant messages, text messages, and voice recordings) which are in the possession, custody or control of NPCC and its affiliates and either: (1) are used in preparation of responses to the attached data requests; (2) relate to any service provided or to be provided by, on behalf of, or for the benefit of NPCC and its affiliates or any facility owned or operated by, on behalf of, or for the benefit of the Company and its affiliates; (3) are communications, transactions, agreements or arrangements between NPCC and any of its affiliates, or between any

director, officer, manager, or other employee of the Company, and any director, officer, manager, or other employee of the Company's affiliates; or (4) relate to the subject matter of any data requests made to NPCC in this audit.

We will contact you shortly to schedule an entrance conference to discuss the nature of the audit engagement. The purposes of the conference call are to: (1) explain the audit process to NPCC; (2) address any questions about the audit that NPCC may have; (3) provide the audit team an opportunity to clarify basic information about NPCC; and (4) discuss the initial data request. If you have any questions concerning this letter, please contact Ms. Adina Mineo, Auditor-in-Charge at (202) 502-6255.

In addition, if you would like to discuss the audit with DA management at any time during the course of this audit, please contact Ms. Teresina Stasko, Branch Chief, at (202) 502-8317, or Mr. Bryan Craig, the Director of the Division of Audits and Chief Accountant, at (202) 502-8741.

Sincerely,

Norman C. Bay
Director
Office of Enforcement

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. PA12-10-000
December 14, 2011

Northeast Power Coordinating Council, Inc.
Attention: Mr. Edward A. Schwerdt
President and Chief Executive Officer
1040 Avenue of the Americas, 10th Floor
New York, NY 10018

RE: Data Request No. 1

Dear Mr. Schwerdt,

By letter dated October 28, 2011 the Office of Enforcement of the Federal Energy Regulatory Commission commenced an audit of Northeast Power Coordinating Council (NPCC).

Attached is Data Request No. 1 (Attachment A) to facilitate our review. Also attached are the General Instructions and Definitions (Attachment B) that govern this data request and all subsequent data requests, should any be required.

Please submit your responses on a rolling basis, with the first set due no later then January 13, 2012, to:

Federal Energy Regulatory Commission
Division of Audits
Attention: Adina Mineo, Rm 51-51
888 First Street, N.E.,
Washington D.C. 20426.

If you have any questions about the data request, please contact Ms. Adina Mineo at (202) 502-6255, or by email at adina.mineo@ferc.gov. If the company cannot provide responses to all of the data requests by the required date, please contact Ms. Mineo at the earliest possible time to discuss the reason for the delay and propose an alternative time table to accommodate the company's needs. The company should, regardless of an inability to provide some responses, provide all responses it can by the deadline above.

This audit is being conducted pursuant to section 215 of the Federal Power Act, 16 U.S.C. § 824o (2006). Documents and information obtained by the Commission staff during the audit, as well as all working papers developed, will be placed in non-public files. Section 39.2(d) of the Commission's regulations, 18 CFR § 39.2(d) (2011), provides that each Regional Entity shall provide the Commission such information as is necessary to implement section 215 of the Federal Power Act.

Sincerely,

Bryan K. Craig
Director and Chief Accountant
Division of Audits
Office of Enforcement

Attachment A - Data Request No. 1
Attachment B - General Definitions and Instructions



Northeast Power Coordinating Council
Compliance Monitoring and Enforcement Program

Entity Guide for Reporting Protection System Misoperations

EG-01

Rev. 0

This non-binding entity guide is provided for NPCC registered entity information and use to assist in processing Protection System Misoperations.

Process Owner:	Manager, Compliance Audit Program	Effective Date: 12/01/11

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Review and Re-Approval Requirements

This document will be reviewed every two years from the effective date, or as appropriate for possible revision. The existing or revised document will be posted to the NPCC website for NPCC registered entity reference.

1. Introduction

All Registered Entities within the NPCC Region are subject to compliance with the NERC Reliability Standards. Entities registered with NERC as Generator Owner (GO), Transmission Owner (TO), or Distribution Provider (DP) with Protection Systems are required to comply with applicable NERC Standards associated with protection system misoperations (*PRC-004*, *PRC-016*, *PRC-022* & *EOP-004*).

NPCC shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations.

PRC-003, Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, is the NERC Reliability Standard which governs the processing of Misoperations. PRC-003 is a "fill in the blank" standards.

NERC issued metric ALR4-1, *Automatic Transmission Outages Caused by Protection System Misoperations* for consistent reporting across NERC and all Regions (Ref. 8.5 & Ref. 8.6).

NPCC has developed this Entity Guide, EG-01 to provide guidance in supporting the above.

Note: All references are listed in Section 8.0.

2. Purpose

The purpose of this procedure is to provide guidance for the consistent, complete and comprehensive capture of protection system misoperations (hereafter known as "misoperations") to ensure that analysis, corrective actions and implementation have been performed so that they can be trended.

This procedure will:

- Provide the entity with a Misoperation Reporting Template (hereafter known as the "template") for capture of misoperation information in a consistent format.
- Describe the roles and responsibilities of personnel responsible for preparing the template, submitting the template, and users of information on the template.
- Provide guidance for the scope of applicable protection systems and reportable misoperations.
- Provide the procedural steps and instructions for preparing, completing and submitting the completed template.
- Provide the schedule for misoperation reporting.

The Misoperation Reporting Template was carefully developed considering the NERC Glossary of Terms and approved NERC Reliability Standards to ensure that there would be no conflicts. The template provides uniform guidance to the Regions as to which Misoperations must be reported per NERC Reliability Standards PRC-004, PRC-016, and PRC-022.

Adherence to this procedure will help the entity improve its compliance position. The template may serve as a work tracking summary sheet for misoperations and their required actions. This will help the entity determine whether all required actions for misoperation reporting have been completed to affirm annual Self Certification of compliance to PRC-004, PRC-016, and PRC-022 as applicable.

The template has been augmented by NPCC with an additional separator for Bulk Power System (BPS) (Ref. 8.13) and with additional explanation of information to be entered in each field (Ref. 8.11 and Ref. 8.12).

3. Applicability

This procedure applies to all NERC registered entities with the following functions:

- Generator Owner (GO)
- Transmission Owner (TO)
- Distribution Provider (DP) with transmission Protection Systems

Hereafter, the above will be referred to as the "entity" or "entities".

4. Roles and Responsibilities

4A. Protection System Subject Matter Expert (SME) - Filling out the Misoperation Reporting Template completely and accurately requires personnel cognizant of the misoperation event, involved in the analysis and corrective actions for correction, and knowledgeable in the terminology and expectations of the Misoperation Reporting Template.

This person is usually part of the entity's Engineering or Protection System group.

4B. NPCC CDAA Technical Contact – Submittal of the Misoperation Reporting Template to support NERC compliance and ERO-RAPA data reporting requires personnel authorized to submit Self Certifications for PRC-004 for the entity using the NPCC CDAA application.

This person may or may not be the same as the Protection System SME.

4C. NPCC Compliance Group – NPCC Compliance staff will consolidate the individual quarterly Misoperation Reporting Templates submitted by the applicable entities and provide them to SP-07 and ERO-RAPA per the requested schedule. Compliance Auditors may review misoperation submittals and their status prior to audits/spot checks of PRC standards.

4D. Protection System Misoperation Review Working Group (SP-07) – will review and analyze misoperations of transmission and generation protection systems and Type 1 Special Protection Systems (SPS) on the Bulk Electric System in the NPCC region. This group will analyze the quarterly Misoperation Reporting Templates submitted to CDAA.

4E. TADS (Transmission Availability Database System) representative – any misoperations on transmission protection systems for 200KV or above are to be captured in the NERC TADS database. If the TADS representative is not the same person as the NPCC CDAA Technical Contact, the TADS representative should be consulted to verify the cause codes and other TADS related fields on the template with the Protection System SME for correctness. The misoperation information should be used by the TADS representative for TADS.

4F. GADS (Generator Availability Database System) representative – any misoperations on generator protection systems material to the Bulk Power System are to be captured in the NERC GADS database. If the GADS representative is not the same person as the NPCC CDAA Technical Contact, the misoperation information should be provided to the GADS representative for data capture in GADS.

5. Definitions/Scope

Definitions

The terminology used herein is defined in the NERC Glossary of Terms (Ref. 8.7)

Further clarification is provided in the list of references shown below. These references do not alter the NERC Glossary of Terms for "Misoperations" and "Protection Systems", nor the requirements in the NERC standards. They provide guidance and clarification to the scope and reportability of misoperations:

- ERO RAPA Letter, Attachment A, *Proposed* Protection System and Misoperation Reporting (Ref. 8.5)
- NERC Webinar on Consistent Reporting of Misoperations (Ref. 8.8)
- NERC Webinar, Misoperations Question and Answers (Ref. 8.9)
- ERO-RAPA Misoperation Reporting Template, "Definitions" tab (Ref. 8.10)

Scope

5A. The specific Protection Systems of interest for which misoperations are to be reported are listed in the NERC Glossary (Ref. 8.7) and repeated in Section 1 of Appendix A in Reference 8.5.

5B. The specific Misoperations of interest are:

- "Dependability" type - when a Protection System does not operate when desired.
- "Security" type – when a Protection System operates when not desired.

These are described in greater detail in Section 2 of Appendix A in Reference 8.5

5C. Pay particular attention to Page 4 of Reference 8.5 for there are nine (9) notes provided which describe very specifically what constitutes "Reportable", and "Non-Reportable" misoperations.

5D. Noteworthy is Note "A" (Page 4 of Reference 8.5) which states:

"The composite Protection System in the context of this standard is the total complement of protection for a system Element (line, bus, transformer, generator, etc). Primary and secondary protection of a given Element is considered as the composite Protection System, not two separate Protection Systems"

- Based on the above definition, consider the following situation: a line is protected by (composite) System A and System B protection systems. A fault occurs on the line. System A fails to operate to clear the fault, but System B successfully operates to clear the fault as designed. This is not a Reportable Misoperation because the **composite** Protection System operated to clear the fault.
- Question 4a and 4b in NERC Webinar, Misoperations Q&A (Reference 8.9) provides additional clarification for the situation above.

5E. Misoperation reporting is required for all GO, TO and DP protection systems that affect the reliability of the Bulk Electric System (BES).

- Currently in NPCC, the BES is the Bulk Power System (BPS) as defined in NPCC Criteria A-10 (Ref. 8.13) and Compliance Guidance Statement, CGS-002, Generation Materiality. A project is underway which may re-define the definition of the BES in the NPCC footprint.
- In order to obtain more complete information to support the NERC ALR4-1 initiative, entities are asked to provide "bright line" (≥ 100kV) misoperations so that this information does not have to be requested later.
  - The template has been modified to include a column to distinguish between BPS and "bright line" misoperations.

5F. Read the other Notes on Page 4 of Reference 8.5, and Reference 8.9, *NERC Webinar Misoperation Reporting Q&A*, which address delayed clearing, targeting, reclosing, human error; maintenance, testing, construction and out-of-service status of equipment and their relationship to misoperations; and fine points for various failure and fault conditions related to misoperations.

6. Procedure

Overview:

6A. There are two processes for Misoperation Reporting:

- Completion of the Misoperation Reporting Template
- Submittal of the Misoperation Reporting Template to NPCC CDAA

6B. Use of the template to capture all misoperations will greatly enhance the reporting process.

- Aside from ensuring consistency, this process will reduce the volume of submittals. If there are new misoperations or updates of previous misoperations to report, the submittal will contain a single template for the applicable misoperations related to the entity's registered function.
- Each misoperation and all its details shall appear on a separate row of the template. All new misoperations, and updates for previously reported misoperations, should appear on the template.
- If the entity is registered for more than one of the GO, TO or DP registered functions, the misoperations for each registered function shall be entered on separate templates.
- It will no longer be necessary to submit individual misoperation report forms for every misoperation to NPCC CDAA.

- If there are no new misoperations, or updates of previously reported misoperations to report, it is not necessary to attach the template to the CDAA submittal. However, a NPCC CDAA submittal is still required (Section 6F).

6C. NPCC CDAA submittals will also be reduced by use of the template.

- Misoperations are required to be submitted on a quarterly basis and not as they happen. See Section 7.0.
- Each entity is required to perform only one quarterly NPCC CDAA submittal for the misoperations related to each of its applicable registered functions.

6D. The template is attached to the NPCC CDAA Misoperation PRC-004 Report Form and submitted by the CDAA Technical Contact prior to the due date shown on CDAA.

6E. Procedure: Misoperation Reporting Template

6E.1. If there are new misoperations, or updates of previous misoperations, to report, they are to be captured on a blank template. If there are none, then skip to Section 6F.

6E.2. Obtain the blank electronic template from the link to Reference 8.10.

- The blank template may also be found on the NPCC CDAA Announcements screen (*future action to be implemented after approval of this procedure*)

6E.3. Begin completing the template with misoperation information from left column to right column. Protection System SME should provide input to the template.

- Each misoperation should be listed on its own row.
- Refer to the ERO example template and NPCC Instructions (Refs. 8.11 & Ref. 8.12)
- Review the scope, template "definitions" tab, and Q&A in the various references for additional guidance in data capture.

6E.4. If this is the first time the misoperation is being reported, choose "Resubmittal" = NO in Column A of the template.

- For previously reported misoperations, choose "Resubmittal" = YES. Resubmittals should appear with mostly duplicate information with updated status and/or more information.

6E.5. If the misoperation involves protection systems for elements on NPCC's A-10 list, or generators material to the Bulk Power System (BPS) per CGS-002, then choose "BPS" = YES in Column AB of the template.

6E.6. If the misoperation involves protection systems for elements that are not NPCC BPS, but are ≥ 100kV, then enter the information and choose "BPS" = NO in Column AB of the template. See Section 5E. for explanation.

6E.7. When completed, save the template with a unique name and syntax in preparation for submittal to NPCC CDAA. Suggestions:

- 2011_1stQtr_Misops_GO_*entityname*.xls
- 2011_1stQtr_Misops_TO_*entityname*.xls
- 2011_2ndQtr_Misops_DP_*entityname*.xls
- 2011_3rdQtr_Misops_TO_*entityname*.xls
- 2011_4thQtr_Misops_GO_*entityname*.xls

6F. Procedure: NPCC Report Form Submittal

NOTE: In the event that the CDAA application is unavailable, or not ready to accommodate the steps listed below, submittal of the Misoperations Report Template in accordance with the reporting schedule (Section 7.0) may be performed using one of the following:

- Submit through secure FTP process with email notification to misoperations@npcc.org
- Submit through password protected zip file attached to email sent to misoperations@npcc.org with a separate follow-up email providing the password.
- Provide ftp address and password for NPCC staff to access and download the template.
- If there are no new misoperations (or updates to previously submitted misoperations) to report for the quarter, simply state so in the email. State the specific quarter, year and the NERC Compliance Registry number of the entity. No attachments are necessary.

The following section is shown as strikethrough because the changes to the NPCC CDAA application have not been implemented to accommodate these changes. When the changes have been implemented, this section will be restored to the procedure

~~6F.1. When the template has been completed, CDAA Technical Contact shall login to the NPCC CDAA application and choose the registered entity and function corresponding to the applicable template.~~

~~6F.2. CDAA Technical Contact shall choose "*PRC-004-1-T RF*" or "*PRC-004-1-G RF*" as applicable from the CDAA screen, by clicking on the "New" icon to the left of the list.~~

~~6F.3. If the entity has no protection systems applicable to PRC-004, then~~

- ~~Check the box "*The NERC Reliability Standard PRC-004-1 does not apply to NPCC because NPCC does not own a transmission Protection System.*"~~
- ~~Check the box "*Ready to Create Certification Statement".*~~
- ~~Save item and submit.~~

~~6F.4. If the entity has no misoperations, nor updates to previously reported misoperations, during the quarter, then~~

- ~~Check the box "There are no reportable misoperations, nor updates to previously reported misoperations, during this period."~~
- ~~Check the box "*Ready to Create Certification Statement".*~~
- ~~Save item and submit.~~

~~6F.5. If the entity has misoperations, or updates to previously reported misoperations, during the quarter, then~~

- ~~Check the box "There are reportable misoperations, or updates to previously reported misoperations, during this period. See attached template."~~
- ~~Click the link named "Attachments (0)" near the top of the screen.~~
- ~~Find the completed Misoperation Reporting template from step 6E.7 and attach it in the dialog box.~~

  ~~Note: Attach the template (".xlsx" file), not a printout (".pdf" file)~~

- ~~Check the box "*Ready to Create Certification Statement".*~~
- ~~Save item and submit.~~

~~6F.6. Repeat as needed for misoperations applicable to other registered functions.~~

6F.7. NPCC Compliance will provide the submitted templates to SP-07 Working Group for review, and consolidate them for submittal to ERO-RAPA per the requested schedule.

7. Misoperations Reporting Schedule

ERO RAPA has suggested the Misoperations Reporting Schedule shown in Section 7.1.

- "NERC Metric Data Due" dates are shown in the third column.
- NERC Proposed "Misoperations Reports Due to Regions" dates are shown in the first column.

NPCC proposes the NPCC CDAA submittal schedule in Section 7.2. It is requested that Quarterly Misoperation Reports be submitted by the 20th day of the month following the end of each quarter.

This earlier due date is requested:

- To provide adequate time for the NPCC Compliance group to compile all quarterly data and
- To allow adequate time for the SP-7 working group to perform reviews prior to the NERC Metric Data due date.

Note: Quarterly misoperation reporting is not the same as certification of compliance to NERC Standard PRC-004, *Analysis and Mitigation of Transmission and Generation Protection System*. Self-certification of compliance to PRC-004, takes place in January of the year following the reporting period (i.e. for the reporting period Jan-Dec 2011, self-certification in NPCC CDAA is due by January 20, 2012).

7.1. ERO-RAPA Misoperations Reporting Schedule

Misoperations Reports Due To Regions	Action	Metric Data Due To NERC
May 31, 2011	Submission of the 1st Quarter 2011 data	July 15, 2011
August 31, 2011	Submission of the 2nd Quarter 2011 data	October 15, 2011
November 30, 2011	Submission of the 3rd Quarter 2011 data	January 15, 2012
February 28, 2012	Submission of the 4th Quarter 2011 data	April 15, 2012
May 31, 2012	Submission of the 1st Quarter 2012 data	July 15, 2012

7.2. NPCC CDAA Submittal Schedule

NPCC CDAA will be programmed to display the following due dates for entities with TO, GO and DP registered functions:

Misoperation Report Data for Calendar Quarter	NPCC CDAA Submittal Due Date
1st Quarter 2011	April 20, 2011
2nd Quarter 2011	July 20, 2011
3rd Quarter 2011	October 20, 2011
4th Quarter 2011	January 20, 2012

8. References

8.1. NERC Reliability Standard PRC-004, Analysis and Mitigation of Transmission and Generation Protection System Misoperations

8.2. NERC Reliability Standard PRC-016, Special Protection System Misoperations

8.3. NERC Reliability Standard PRC-022, Under-Voltage Load Shedding Program Performance

8.4. NERC Reliability Standard EOP-004, Disturbance Reporting

8.5. NERC ERO-RAPA Letter to Regional Executives, 10-12-2010

8.6. NERC ERO-RAPA Letter to Regional Executives, 01-17-2011

8.7. NERC Glossary of Terms - Misoperations, Protection Systems

8.8. NERC Webinar, Consistent Protection System Misoperation Reporting 02-10-2011

8.9. NERC Webinar, Misoperation Reporting Q&A

8.10. ERO-RAPA Misoperation Reporting Template (blank)

8.11. Misoperation Reporting Template - ERO example

8.12. Misoperation Reporting Template - NPCC Instructions

8.13. NPCC Criteria A-10, Classification of Bulk Power System Elements, 12-01-09

8.14. NPCC Compliance Guidance Statement, CGS-002, Generation Materiality

8.15. NPCC Document C-45, Procedure for Analysis and Reporting of Protection System Misoperations

9. Summary of Changes

Revision 0

None – This procedure is the original issue.

From:	Guy V. Zito
To:	yujie.lu@us.ngrid.com
Cc:	tfsp
Subject:	RE: FERC Acceptance for Filing in RM12-6-000
Date:	Monday, January 30, 2012 12:38:22 PM

Hi Irene,

I will include this as a discussion item at the joint RSC CC meeting. The CEAP is something done only for new regional standards brought before the stakeholders and Board of Directors at NPCC. I would not advise anyone to not proceed with an aggressive implementation of the Regional Standard, and also consider in that implementation, the potential FERC acceptance of the applicablity of the 100 kV BES Brite Line to this and all standards. I will report the discussion with the joint RSC CC meeting to the TFSP for their information.

Best Regards,

Guy

_____
From: Lu, Yujie I. [YUJIE.LU@us.ngrid.com]
Sent: Friday, January 27, 2012 4:32 PM
To: Guy V. Zito; tfsp
Subject: RE: FERC Acceptance for Filing in RM12-6-000

Hi Guy,

Thank you.

Do you still suggest us to hold on it? And do you think we still should consider a cost-effective study (support for technical justification) at this time?

Regards,
Y. Irene Lu, PE
Principal Engineer
Protection Policy & Supports
National Grid
Waltham, MA
781-907-3227

-----Original Message-----
From: Guy V. Zito [mailto:gzito@npcc.org]
Sent: Thursday, January 26, 2012 12:16 PM
To: tfsp
Subject: FW: FERC Acceptance for Filing in RM12-6-000

TFSP,

See below. The NERC BES filing has been completed so the approach we discussed regarding the NPCC-PRC-002 will have to change. Based on our discussions I was hoping to be able to work with NERC to clarify implementation issues and the applicability issue in this filing.

In March the RSC will meet with the CC to discuss compliance and other

issues pertaining to this standard further, as well as the Directory issue.

Thank you Daren and all for allowing me to attend the meeting and participate. I found the TFSP to be an expecially dedicated and passionate group of professionals and found the meeting very worthwhile. I look forward to working more closely with TFSP in the future to address standards and directory related issues in what certainly will prove to continue to deliver ever increasing challenges and opportunities to us all.

Thanks,

Guy V. Zito

Assistant Vice President-Standards

Northeast Power Coordinating Council, Inc.

1040 Avenue of the Americas, 10 th Floor

New York, NY 10018

212-840-1070

212-302-2782 fax

From: Philip A. Fedora

Sent: Wednesday, January 25, 2012 2:55 PM

To: grpStaff

Subject: FW: FERC Acceptance for Filing in RM12-6-000

FYI - Phil

-----Original Message-----

From: Ed Dobrowolski [mailto:Ed.Dobrowolski@nerc.net]

Sent: Wednesday, January 25, 2012 2:54 PM

To: dbessdt_plus

Subject: FW: FERC Acceptance for Filing in RM12-6-000

Here is the link to the filing.

Edd

Edward J. Dobrowolski

NERC

Standards Development Advisor

1.609.947.3673

Mark Twain: "Travel is fatal to prejudice, bigotry, and narrow-mindedness."

-----Original Message-----

From: MacBride, Owen E. [mailto:omacbride@schiffhardin.com]

Sent: Wednesday, January 25, 2012 2:53 PM

To: David Cook; Herb Schrayshuen; Ed Dobrowolski; Andrew Dressel; Andy Rodriquez; David Taylor; 'Cole, Mark'; 'cedge@serc1.org'; Heidrich, Peter; 'barry.lawson@nreca.coop'

Subject: FW: FERC Acceptance for Filing in RM12-6-000

This is the FERC Notice of Acceptance for Filing of the BES Definition Petition. The filing is directly accessible from the FERC e-library website via the link below.

Owen E. MacBride

(312) 258-5680

(312) 258-5700 fax

omacbride@schiffhardin.com

-----Original Message-----

From: eFiling@ferc.gov [mailto:eFiling@ferc.gov]

Sent: Wednesday, January 25, 2012 1:49 PM

To: MacBride, Owen E.; eFiling@ferc.gov

Subject: FERC Acceptance for Filing in RM12-6-000

Acceptance for Filing

The FERC Office of the Secretary has accepted the following electronic submission for filing (Acceptance for filing does not constitute approval of any application or self-certifying notice):

-Accession No.: 201201255142

-Docket(s) No.: RM12-6-000

-Filed By: North American Electric Reliability Corporation -Signed By: Owen MacBride -Filing Type: Reliability Std. -approval, remand, or modification -Filing Desc: Petition of the North American Electric Reliability Corporation for Approval of a Revised Definition of "Bulk Electric System" in the NERC Glossary of Terms Used in Reliability Standards -Submission Date/Time: 1/25/2012 1:04:36 PM -Filed Date: 1/25/2012 1:04:36 PM

Your submission is now part of the record for the above Docket(s) and available in FERC's eLibrary system at:

http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20120125-5142

If you would like to receive e-mail notification when additional documents are added to the above docket(s), you can eSubscribe by docket at:

https://ferconline.ferc.gov/eSubscription.aspx

There may be a 10 minute delay before the document appears in eLibrary.

Thank you again for using the FERC Electronic Filing System. If you need to contact us for any reason:

E-Mail: efiling@ferc.gov mailto:efiling@ferc.gov (do not send filings to this address) Voice Mail: 202-502-8258.

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Northeast Power Coordinating Council
Compliance Monitoring and Enforcement Program

Entity Guide for Reporting Protection System Misoperations

EG-01

Rev. 0

This non-binding entity guide is provided for NPCC registered entity information and use to assist in processing Protection System Misoperations.

Process Owner:	Manager, Compliance Audit Program	Effective Date: 12/01/11

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Review and Re-Approval Requirements

This document will be reviewed every two years from the effective date, or as appropriate for possible revision. The existing or revised document will be posted to the NPCC website for NPCC registered entity reference.

1. Introduction

All Registered Entities within the NPCC Region are subject to compliance with the NERC Reliability Standards. Entities registered with NERC as Generator Owner (GO), Transmission Owner (TO), or Distribution Provider (DP) with Protection Systems are required to comply with applicable NERC Standards associated with protection system misoperations (*PRC-004*, *PRC-016*, *PRC-022* & *EOP-004*).

NPCC shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations.

PRC-003, Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, is the NERC Reliability Standard which governs the processing of Misoperations. PRC-003 is a "fill in the blank" standards.

NERC issued metric ALR4-1, *Automatic Transmission Outages Caused by Protection System Misoperations* for consistent reporting across NERC and all Regions (Ref. 8.5 & Ref. 8.6).

NPCC has developed this Entity Guide, EG-01 to provide guidance in supporting the above.

Note: All references are listed in Section 8.0.

2. Purpose

The purpose of this procedure is to provide guidance for the consistent, complete and comprehensive capture of protection system misoperations (hereafter known as "misoperations") to ensure that analysis, corrective actions and implementation have been performed so that they can be trended.

This procedure will:

- Provide the entity with a Misoperation Reporting Template (hereafter known as the "template") for capture of misoperation information in a consistent format.
- Describe the roles and responsibilities of personnel responsible for preparing the template, submitting the template, and users of information on the template.
- Provide guidance for the scope of applicable protection systems and reportable misoperations.
- Provide the procedural steps and instructions for preparing, completing and submitting the completed template.
- Provide the schedule for misoperation reporting.

The Misoperation Reporting Template was carefully developed considering the NERC Glossary of Terms and approved NERC Reliability Standards to ensure that there would be no conflicts. The template provides uniform guidance to the Regions as to which Misoperations must be reported per NERC Reliability Standards PRC-004, PRC-016, and PRC-022.

Adherence to this procedure will help the entity improve its compliance position. The template may serve as a work tracking summary sheet for misoperations and their required actions. This will help the entity determine whether all required actions for misoperation reporting have been completed to affirm annual Self Certification of compliance to PRC-004, PRC-016, and PRC-022 as applicable.

The template has been augmented by NPCC with an additional separator for Bulk Power System (BPS) (Ref. 8.13) and with additional explanation of information to be entered in each field (Ref. 8.11 and Ref. 8.12).

3. Applicability

This procedure applies to all NERC registered entities with the following functions:

- Generator Owner (GO)
- Transmission Owner (TO)
- Distribution Provider (DP) with transmission Protection Systems

Hereafter, the above will be referred to as the "entity" or "entities".

4. Roles and Responsibilities

4A. Protection System Subject Matter Expert (SME) - Filling out the Misoperation Reporting Template completely and accurately requires personnel cognizant of the misoperation event, involved in the analysis and corrective actions for correction, and knowledgeable in the terminology and expectations of the Misoperation Reporting Template.

This person is usually part of the entity's Engineering or Protection System group.

4B. NPCC CDAA Technical Contact – Submittal of the Misoperation Reporting Template to support NERC compliance and ERO-RAPA data reporting requires personnel authorized to submit Self Certifications for PRC-004 for the entity using the NPCC CDAA application.

This person may or may not be the same as the Protection System SME.

4C. NPCC Compliance Group – NPCC Compliance staff will consolidate the individual quarterly Misoperation Reporting Templates submitted by the applicable entities and provide them to SP-07 and ERO-RAPA per the requested schedule. Compliance Auditors may review misoperation submittals and their status prior to audits/spot checks of PRC standards.

4D. Protection System Misoperation Review Working Group (SP-07) – will review and analyze misoperations of transmission and generation protection systems and Type 1 Special Protection Systems (SPS) on the Bulk Electric System in the NPCC region. This group will analyze the quarterly Misoperation Reporting Templates submitted to CDAA.

4E. TADS (Transmission Availability Database System) representative – any misoperations on transmission protection systems for 200KV or above are to be captured in the NERC TADS database. If the TADS representative is not the same person as the NPCC CDAA Technical Contact, the TADS representative should be consulted to verify the cause codes and other TADS related fields on the template with the Protection System SME for correctness. The misoperation information should be used by the TADS representative for TADS.

4F. GADS (Generator Availability Database System) representative – any misoperations on generator protection systems material to the Bulk Power System are to be captured in the NERC GADS database. If the GADS representative is not the same person as the NPCC CDAA Technical Contact, the misoperation information should be provided to the GADS representative for data capture in GADS.

5. Definitions/Scope

Definitions

The terminology used herein is defined in the NERC Glossary of Terms (Ref. 8.7)

Further clarification is provided in the list of references shown below. These references do not alter the NERC Glossary of Terms for "Misoperations" and "Protection Systems", nor the requirements in the NERC standards. They provide guidance and clarification to the scope and reportability of misoperations:

- ERO RAPA Letter, Attachment A, *Proposed* Protection System and Misoperation Reporting (Ref. 8.5)
- NERC Webinar on Consistent Reporting of Misoperations (Ref. 8.8)
- NERC Webinar, Misoperations Question and Answers (Ref. 8.9)
- ERO-RAPA Misoperation Reporting Template, "Definitions" tab (Ref. 8.10)

Scope

5A. The specific Protection Systems of interest for which misoperations are to be reported are listed in the NERC Glossary (Ref. 8.7) and repeated in Section 1 of Appendix A in Reference 8.5.

5B. The specific Misoperations of interest are:

- "Dependability" type - when a Protection System does not operate when desired.
- "Security" type – when a Protection System operates when not desired.

These are described in greater detail in Section 2 of Appendix A in Reference 8.5

5C. Pay particular attention to Page 4 of Reference 8.5 for there are nine (9) notes provided which describe very specifically what constitutes "Reportable", and "Non-Reportable" misoperations.

5D. Noteworthy is Note "A" (Page 4 of Reference 8.5) which states:

"The composite Protection System in the context of this standard is the total complement of protection for a system Element (line, bus, transformer, generator, etc). Primary and secondary protection of a given Element is considered as the composite Protection System, not two separate Protection Systems"

- Based on the above definition, consider the following situation: a line is protected by (composite) System A and System B protection systems. A fault occurs on the line. System A fails to operate to clear the fault, but System B successfully operates to clear the fault as designed. This is not a Reportable Misoperation because the **composite** Protection System operated to clear the fault.
- Question 4a and 4b in NERC Webinar, Misoperations Q&A (Reference 8.9) provides additional clarification for the situation above.

5E. Misoperation reporting is required for all GO, TO and DP protection systems that affect the reliability of the Bulk Electric System (BES).

- Currently in NPCC, the BES is the Bulk Power System (BPS) as defined in NPCC Criteria A-10 (Ref. 8.13) and Compliance Guidance Statement, CGS-002, Generation Materiality. A project is underway which may re-define the definition of the BES in the NPCC footprint.
- In order to obtain more complete information to support the NERC ALR4-1 initiative, entities are asked to provide "bright line" (≥ 100kV) misoperations so that this information does not have to be requested later.
  - The template has been modified to include a column to distinguish between BPS and "bright line" misoperations.

5F. Read the other Notes on Page 4 of Reference 8.5, and Reference 8.9, *NERC Webinar Misoperation Reporting Q&A*, which address delayed clearing, targeting, reclosing, human error; maintenance, testing, construction and out-of-service status of equipment and their relationship to misoperations; and fine points for various failure and fault conditions related to misoperations.

6. Procedure

Overview:

6A. There are two processes for Misoperation Reporting:

- Completion of the Misoperation Reporting Template
- Submittal of the Misoperation Reporting Template to NPCC CDAA

6B. Use of the template to capture all misoperations will greatly enhance the reporting process.

- Aside from ensuring consistency, this process will reduce the volume of submittals. If there are new misoperations or updates of previous misoperations to report, the submittal will contain a single template for the applicable misoperations related to the entity's registered function.
- Each misoperation and all its details shall appear on a separate row of the template. All new misoperations, and updates for previously reported misoperations, should appear on the template.
- If the entity is registered for more than one of the GO, TO or DP registered functions, the misoperations for each registered function shall be entered on separate templates.
- It will no longer be necessary to submit individual misoperation report forms for every misoperation to NPCC CDAA.

- If there are no new misoperations, or updates of previously reported misoperations to report, it is not necessary to attach the template to the CDAA submittal. However, a NPCC CDAA submittal is still required (Section 6F).

6C. NPCC CDAA submittals will also be reduced by use of the template.

- Misoperations are required to be submitted on a quarterly basis and not as they happen. See Section 7.0.
- Each entity is required to perform only one quarterly NPCC CDAA submittal for the misoperations related to each of its applicable registered functions.

6D. The template is attached to the NPCC CDAA Misoperation PRC-004 Report Form and submitted by the CDAA Technical Contact prior to the due date shown on CDAA.

6E. Procedure: Misoperation Reporting Template

6E.1. If there are new misoperations, or updates of previous misoperations, to report, they are to be captured on a blank template. If there are none, then skip to Section 6F.

6E.2. Obtain the blank electronic template from the link to Reference 8.10.

- The blank template may also be found on the NPCC CDAA Announcements screen (*future action to be implemented after approval of this procedure*)

6E.3. Begin completing the template with misoperation information from left column to right column. Protection System SME should provide input to the template.

- Each misoperation should be listed on its own row.
- Refer to the ERO example template and NPCC Instructions (Refs. 8.11 & Ref. 8.12)
- Review the scope, template "definitions" tab, and Q&A in the various references for additional guidance in data capture.

6E.4. If this is the first time the misoperation is being reported, choose "Resubmittal" = NO in Column A of the template.

- For previously reported misoperations, choose "Resubmittal" = YES. Resubmittals should appear with mostly duplicate information with updated status and/or more information.

6E.5. If the misoperation involves protection systems for elements on NPCC's A-10 list, or generators material to the Bulk Power System (BPS) per CGS-002, then choose "BPS" = YES in Column AB of the template.

6E.6. If the misoperation involves protection systems for elements that are not NPCC BPS, but are ≥ 100kV, then enter the information and choose "BPS" = NO in Column AB of the template. See Section 5E. for explanation.

6E.7. When completed, save the template with a unique name and syntax in preparation for submittal to NPCC CDAA. Suggestions:

- 2011_1stQtr_Misops_GO_*entityname*.xls
- 2011_1stQtr_Misops_TO_*entityname*.xls
- 2011_2ndQtr_Misops_DP_*entityname*.xls
- 2011_3rdQtr_Misops_TO_*entityname*.xls
- 2011_4thQtr_Misops_GO_*entityname*.xls

6F. Procedure: NPCC Report Form Submittal

NOTE: In the event that the CDAA application is unavailable, or not ready to accommodate the steps listed below, submittal of the Misoperations Report Template in accordance with the reporting schedule (Section 7.0) may be performed using one of the following:

- Submit through secure FTP process with email notification to misoperations@npcc.org
- Submit through password protected zip file attached to email sent to misoperations@npcc.org with a separate follow-up email providing the password.
- Provide ftp address and password for NPCC staff to access and download the template.
- If there are no new misoperations (or updates to previously submitted misoperations) to report for the quarter, simply state so in the email. State the specific quarter, year and the NERC Compliance Registry number of the entity. No attachments are necessary.

The following section is shown as strikethrough because the changes to the NPCC CDAA application have not been implemented to accommodate these changes. When the changes have been implemented, this section will be restored to the procedure

~~6F.1. When the template has been completed, CDAA Technical Contact shall login to the NPCC CDAA application and choose the registered entity and function corresponding to the applicable template.~~

~~6F.2. CDAA Technical Contact shall choose "*PRC-004-1-T RF*" or "*PRC-004-1-G RF*" as applicable from the CDAA screen, by clicking on the "New" icon to the left of the list.~~

~~6F.3. If the entity has no protection systems applicable to PRC-004, then~~

- ~~Check the box "*The NERC Reliability Standard PRC-004-1 does not apply to NPCC because NPCC does not own a transmission Protection System.*"~~
- ~~Check the box "*Ready to Create Certification Statement".*~~
- ~~Save item and submit.~~

~~6F.4. If the entity has no misoperations, nor updates to previously reported misoperations, during the quarter, then~~

- ~~Check the box "There are no reportable misoperations, nor updates to previously reported misoperations, during this period."~~
- ~~Check the box "*Ready to Create Certification Statement".*~~
- ~~Save item and submit.~~

~~6F.5. If the entity has misoperations, or updates to previously reported misoperations, during the quarter, then~~

- ~~Check the box "There are reportable misoperations, or updates to previously reported misoperations, during this period. See attached template."~~
- ~~Click the link named "Attachments (0)" near the top of the screen.~~
- ~~Find the completed Misoperation Reporting template from step 6E.7 and attach it in the dialog box.~~

  ~~Note: Attach the template (".xlsx" file), not a printout (".pdf" file)~~

- ~~Check the box "*Ready to Create Certification Statement".*~~
- ~~Save item and submit.~~

~~6F.6. Repeat as needed for misoperations applicable to other registered functions.~~

6F.7. NPCC Compliance will provide the submitted templates to SP-07 Working Group for review, and consolidate them for submittal to ERO-RAPA per the requested schedule.

7. Misoperations Reporting Schedule

ERO RAPA has suggested the Misoperations Reporting Schedule shown in Section 7.1.

- "NERC Metric Data Due" dates are shown in the third column.
- NERC Proposed "Misoperations Reports Due to Regions" dates are shown in the first column.

NPCC proposes the NPCC CDAA submittal schedule in Section 7.2. It is requested that Quarterly Misoperation Reports be submitted by the 20th day of the month following the end of each quarter.

This earlier due date is requested:

- To provide adequate time for the NPCC Compliance group to compile all quarterly data and
- To allow adequate time for the SP-7 working group to perform reviews prior to the NERC Metric Data due date.

Note: Quarterly misoperation reporting is not the same as certification of compliance to NERC Standard PRC-004, *Analysis and Mitigation of Transmission and Generation Protection System*. Self-certification of compliance to PRC-004, takes place in January of the year following the reporting period (i.e. for the reporting period Jan-Dec 2011, self-certification in NPCC CDAA is due by January 20, 2012).

7.1. ERO-RAPA Misoperations Reporting Schedule

Misoperations Reports Due To Regions	Action	Metric Data Due To NERC
May 31, 2011	Submission of the 1st Quarter 2011 data	July 15, 2011
August 31, 2011	Submission of the 2nd Quarter 2011 data	October 15, 2011
November 30, 2011	Submission of the 3rd Quarter 2011 data	January 15, 2012
February 28, 2012	Submission of the 4th Quarter 2011 data	April 15, 2012
May 31, 2012	Submission of the 1st Quarter 2012 data	July 15, 2012

7.2. NPCC CDAA Submittal Schedule

NPCC CDAA will be programmed to display the following due dates for entities with TO, GO and DP registered functions:

Misoperation Report Data for Calendar Quarter	NPCC CDAA Submittal Due Date
1st Quarter 2011	April 20, 2011
2nd Quarter 2011	July 20, 2011
3rd Quarter 2011	October 20, 2011
4th Quarter 2011	January 20, 2012

8. References

8.1. NERC Reliability Standard PRC-004, Analysis and Mitigation of Transmission and Generation Protection System Misoperations

8.2. NERC Reliability Standard PRC-016, Special Protection System Misoperations

8.3. NERC Reliability Standard PRC-022, Under-Voltage Load Shedding Program Performance

8.4. NERC Reliability Standard EOP-004, Disturbance Reporting

8.5. NERC ERO-RAPA Letter to Regional Executives, 10-12-2010

8.6. NERC ERO-RAPA Letter to Regional Executives, 01-17-2011

8.7. NERC Glossary of Terms - Misoperations, Protection Systems

8.8. NERC Webinar, Consistent Protection System Misoperation Reporting 02-10-2011

8.9. NERC Webinar, Misoperation Reporting Q&A

8.10. ERO-RAPA Misoperation Reporting Template (blank)

8.11. Misoperation Reporting Template - ERO example

8.12. Misoperation Reporting Template - NPCC Instructions

8.13. NPCC Criteria A-10, Classification of Bulk Power System Elements, 12-01-09

8.14. NPCC Compliance Guidance Statement, CGS-002, Generation Materiality

8.15. NPCC Document C-45, Procedure for Analysis and Reporting of Protection System Misoperations

9. Summary of Changes

Revision 0

None – This procedure is the original issue.

From: Tina McClellan
To: Tina McClellan
Subject: NERC: POSTED: Board of Trustees, Board Committees Meeting Agendas
Date: Monday, January 30, 2012 2:07:07 AM

Conference Call and Meeting Agendas — Posted

Finance and Audit Committee Conference Call Agenda
February 3, 2012 – 11:00 a.m. Eastern

Corporate Governance and Human Resources Committee Conference Call Agenda
February 8, 2012 – 7:30 a.m. Mountain – Phoenix, AZ

Standards Oversight and Technology Committee Meeting Agenda
February 8, 2012 – 9:15 a.m. Mountain – Phoenix, AZ

Compliance Committee Meeting Agenda
February 8, 2012 – 10:45 a.m. Mountain – Phoenix, AZ

Board of Trustees Meeting Agenda
February 9, 2012 – 8:00 a.m. Mountain – Phoenix, AZ

For more information or assistance, please contact Tina McClellan (via email) or 404-446-2564.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Standards Oversight and Technology Committee (SOTC)

February 8, 2012 | 9:15–10:30 a.m. Mountain

Arizona Grand Resort
8000 S. Arizona Grand Parkway
Phoenix, AZ 85044
602-438-9000

Introductions and Chair's Remarks

NERC Antitrust Compliance Guidelines

Agenda

1. **Minutes* – Approve**
   a. November 2, 2011 Meeting
2. **SOTC Self-Assessment Results* – Review**
3. **Information Technology (IT)***
   a. NERC/ERO IT Initiatives Update
   b. Progress on IT Developments and Plans for NERC
   c. IDC Transition
4. **Reliability Standards Policy and Guidance***
   a. Generator Operator (GO)/Transmission Operator (TO)
   b. COM-002 Interpretation
5. **Reliability Standards Status Report***
6. **Standards Committee Report to SOTC***

*Background materials included.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

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

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Draft Minutes
Standards Oversight and Technology Committee

November 2, 2011 | 9:00-10:30 a.m. Eastern
Westin Buckhead Atlanta
3391 Peachtree Road, NE
Atlanta, GA 30326

Chair Ken Peterson convened a duly noticed open meeting of the Standards Oversight and Technology Committee of the North American Electric Reliability Corporation on November 2, 2011 at 9:00 a.m. local time, and a quorum was declared present. The agenda is attached as **Exhibit A**.

NERC Antitrust Compliance Guidelines
Chair Peterson directed the participants' attention to the NERC Antitrust Compliance Guidelines.

Minutes
The committee approved the August 3, 2011 meeting minutes (**Exhibit B**).

Standards Presentation and Policy Issues for Discussion and Guidance
Herb Schrayshuen, vice president and director of standards, provided a presentation (**Exhibit C**) where he reviewed policy related items for discussion and guidance.

Update on Proposals to Revise Violation Risk Factor (VRF)/Violation Severity Level (VSL) Criteria
Mr. Schrayshuen reviewed that an updated set of definitions, as well as an updated tool for use in analyzing VRFs, is being prepared for a second round of industry comment, as well as a generalized approach for creating VSLs to be used in lieu of the current approach of performing an exhaustive analysis of possible violations for inclusion in the VSLs is in development. Both proposals will be vetted through NERC staff and Regional Entities and staff's position and regional input will be provided in an update to the Standards Committee (SC) and Compliance and Certification Committee (CCC) at the SC meeting in December.

Balanced Assessment of NERC Reliability Standards
Mr. Schrayshuen reviewed the current reliability standards development process and presented questions for consideration and discussion by the SOTC. Chair Peterson stated early alerts on issues that could potentially create problems for NERC is highly recommended. Further discussion ensued on the current process; is there a need for included SOTC input during the process and at what point and level. Gerry Cauley, President and CEO of NERC, and Allen Mosher, Chair of Standards Committee, both agreed that the current procedure is viable, and Mr. Mosher's suggestion is to obtain good technical input from NERC staff and that input is submitted during the process. His long standing goal is to obtain

written input early in the process from FERC and NERC staff and the Regional Entity staff, as well as input from the regional compliance staff to understand how the standard is going to be enforced. Mr. Mosher stated you have to make a judgment on what is the best reliable standard and that takes balance but committed as Chair of the SC to advise of the tough standards earlier for review and guidance.

ANSI – Forward Looking Obligations

Mr. Schrayshuen reviewed NERC received notice that effective September 9, 2011; NERC's standard development process has been re-approved as an ANSI-accredited standard development process and that the following statement was included in the approval letter:

"NERC is expected to continue to make progress towards its stated goal of submitting documents to ANSI for consideration as proposed American National Standards (ANS)."

Mr. Schrayshuen presented two options for consideration and discussion: 1) reaccredit every five years as NERC has been; or 2) move to a continual accreditation process by submitting standards to ANSI for approval.

Chair Peterson stated he does not feel this item is well enough developed to move forward with guidance discussion today. He requested NERC review further and report back to the committee. Mr. Cauley referred to David Cook, NERC General Counsel, to review current process. Mr. Cook stated that his understanding is there is a five year review to determine if everything is ok; NERC's current process does that; however he would review NERC's procedures and FERC directives to determine if either counters that understanding. If there is a difference, Mr. Cook will report back to the committee at is February 2012 meeting.

Industry Request to Change Our Position on CIP v4

Chair Peterson stated there was not enough time at the current SOTC meeting to hold the discussion on CIP v4 and that CIP v4 would be thoroughly reviewed and discussed at the MRC meeting and the committee would not feel comfortable speaking on this issue without first hearing the discussion to be presented at the MRC meeting.

Standards Committee Report

Due to timing Chair Peterson referenced the Standards Committee report in the Agenda package and asked if there were any comments/questions by the committee; there were none. (**Exhibit D**).

NASPI Update and Presentations

Mark Lauby, Vice President and Director of Reliability Assessment and Performance Analysis, reviewed that Russell Robertson, GPA Director, and Alison Silverstein, NASPI Project Manager would provide status reports on both NASPI and GPA activities and give a preview of upcoming deliverables in 2012. Alison Silverstein, NASPI project manager, reviewed NASPI's recent accomplishments, outlined plans for 2012, and outlined the NERC-DOE plan to mainstream NASPI community activities over the next three years (**Exhibit E**). Russell Robertson, GPA director, reviewed GPA's recent deliverables and accomplishments and outlined GPA's plans and major work products for the coming year (**Exhibit F**).

ERO Enterprise Solutions Roadmap
Catherine Sills, Manager ERO Enterprise Projects, provided a status update on the ERO Enterprise Solutions Roadmap. Mr. Cauley stated that he is pleased with the work over the past year and is continuing to move everything forward. Ms. Sills' presentation is attached as **Exhibit G**.

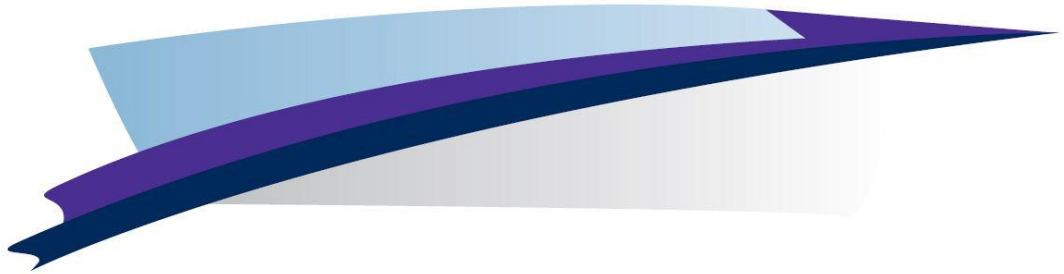
IT 90-Day Plan and Roadmap Update
Marvin Santerfeit, Director of Information Technology and Services, provided a status update on the IT 90-Day Plan and Roadmap. His presentation is attached as **Exhibit H**.

There being no further business, Chair Peterson adjourned the meeting at 10:34 a.m.

Submitted by,



Herb Schrayshuen



TALENTQUEST

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2011 Board of Trustees Standards Oversight & Technology Survey

Overview

- TalentQuest worked with NERC to conduct its annual Board of Trustees - Standards Oversight and Technology Committee (SOTC) survey through an online methodology

- The Standards Oversight and Technology Committee survey was administered from December 1-21, 2011 to a total of 6 Committee members

- 6 Committee members responded to the survey
  - Response rate of 100%

Rating Scale

Respondents were asked to rate items on a 1 to 5 scale to indicate their level of agreement with each item.

1 = Needs Prompt Attention *(level of performance is clearly unsatisfactory)*

2 = Below Expectations *(a question exists in the rater's mind as to the level of performance)*

3 = Meets Expectations *(meets the required standard of performance)*

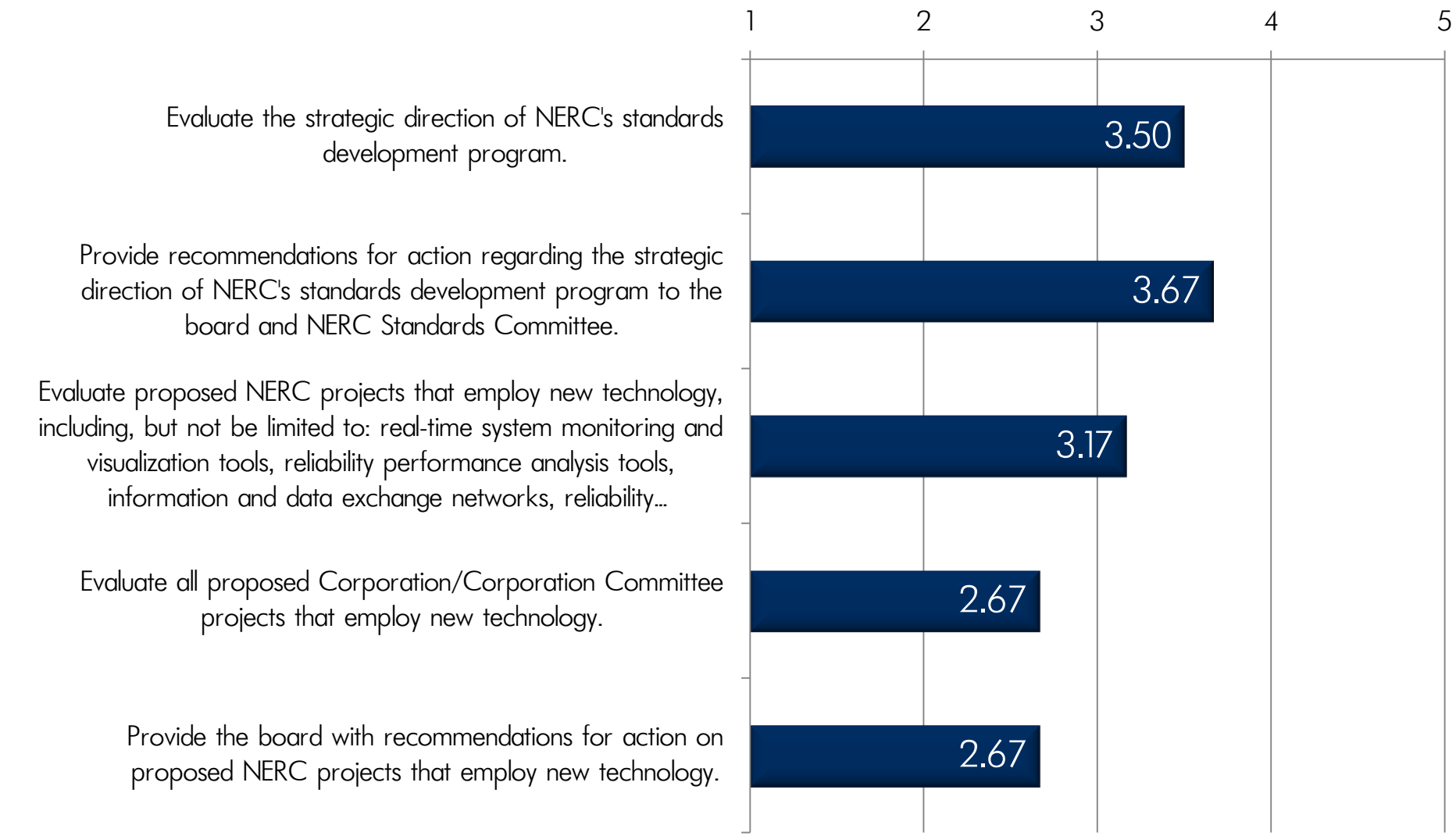
4 = Exceeds Expectations *(fully meets and exceeds the expected and required standard of performance)*

5 = Outstanding *(far exceeds the required standards of performance)*

TalentQuest

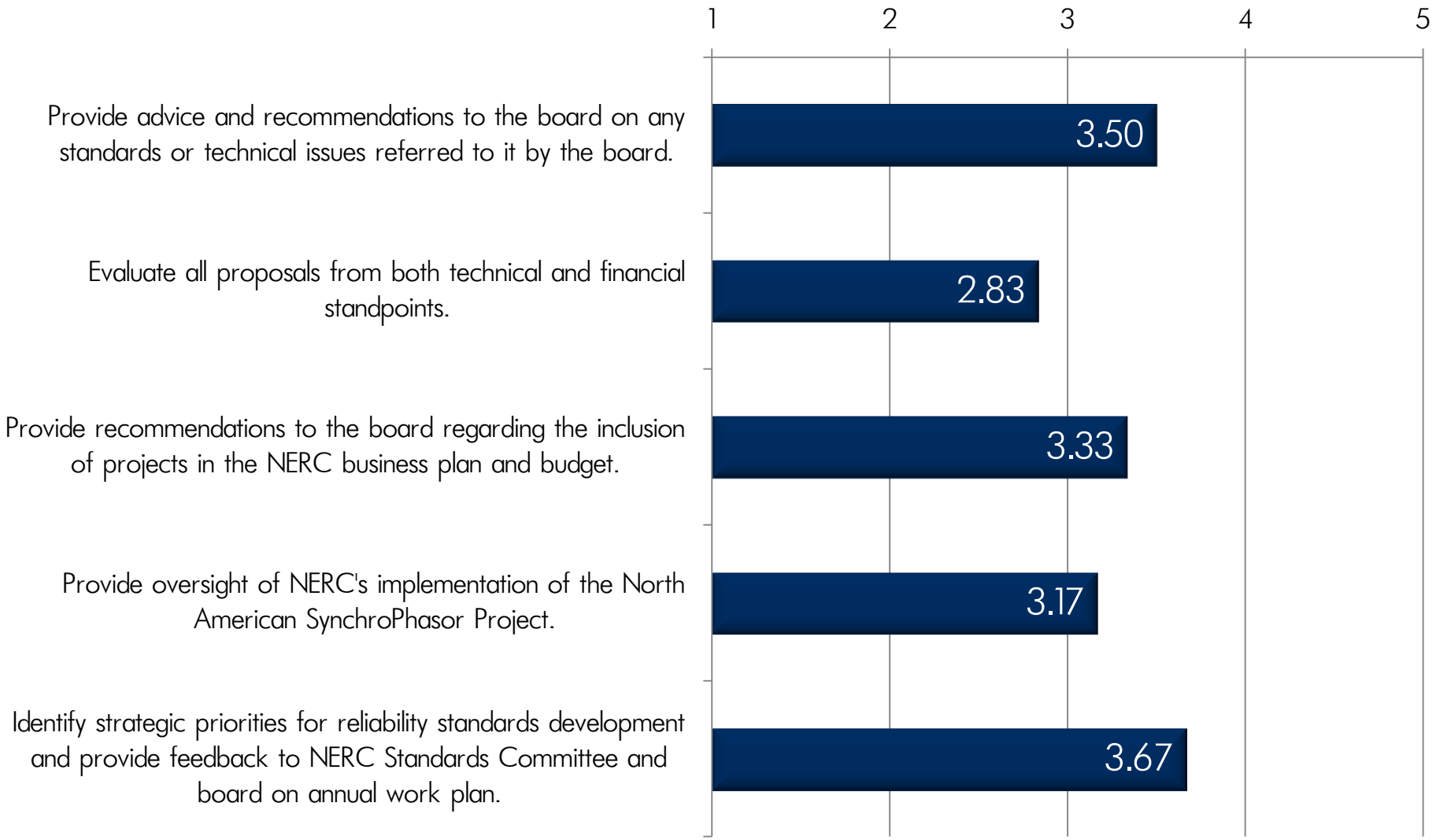
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SOTC (1 of 4)



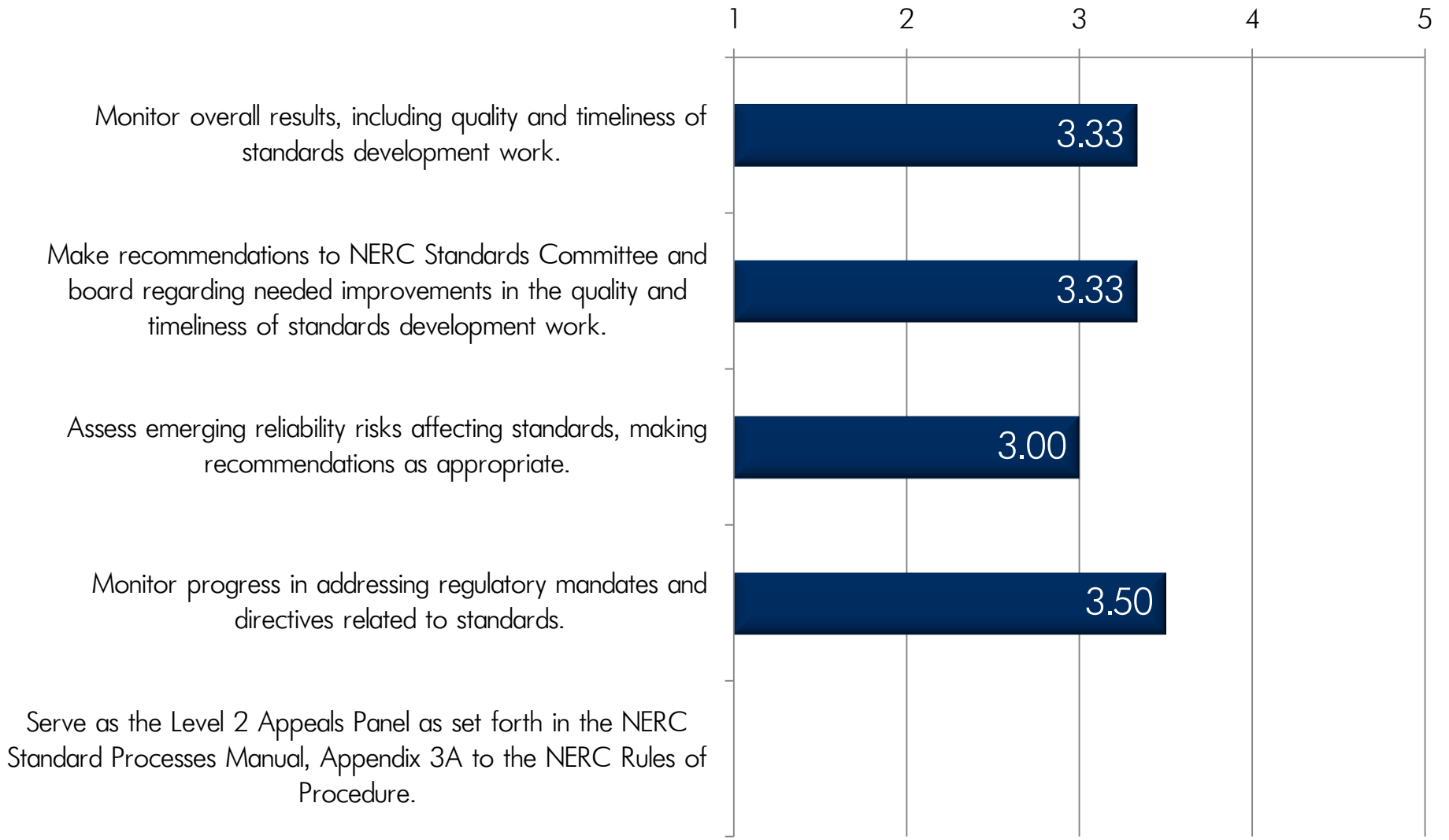
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SOTC (2 of 4)



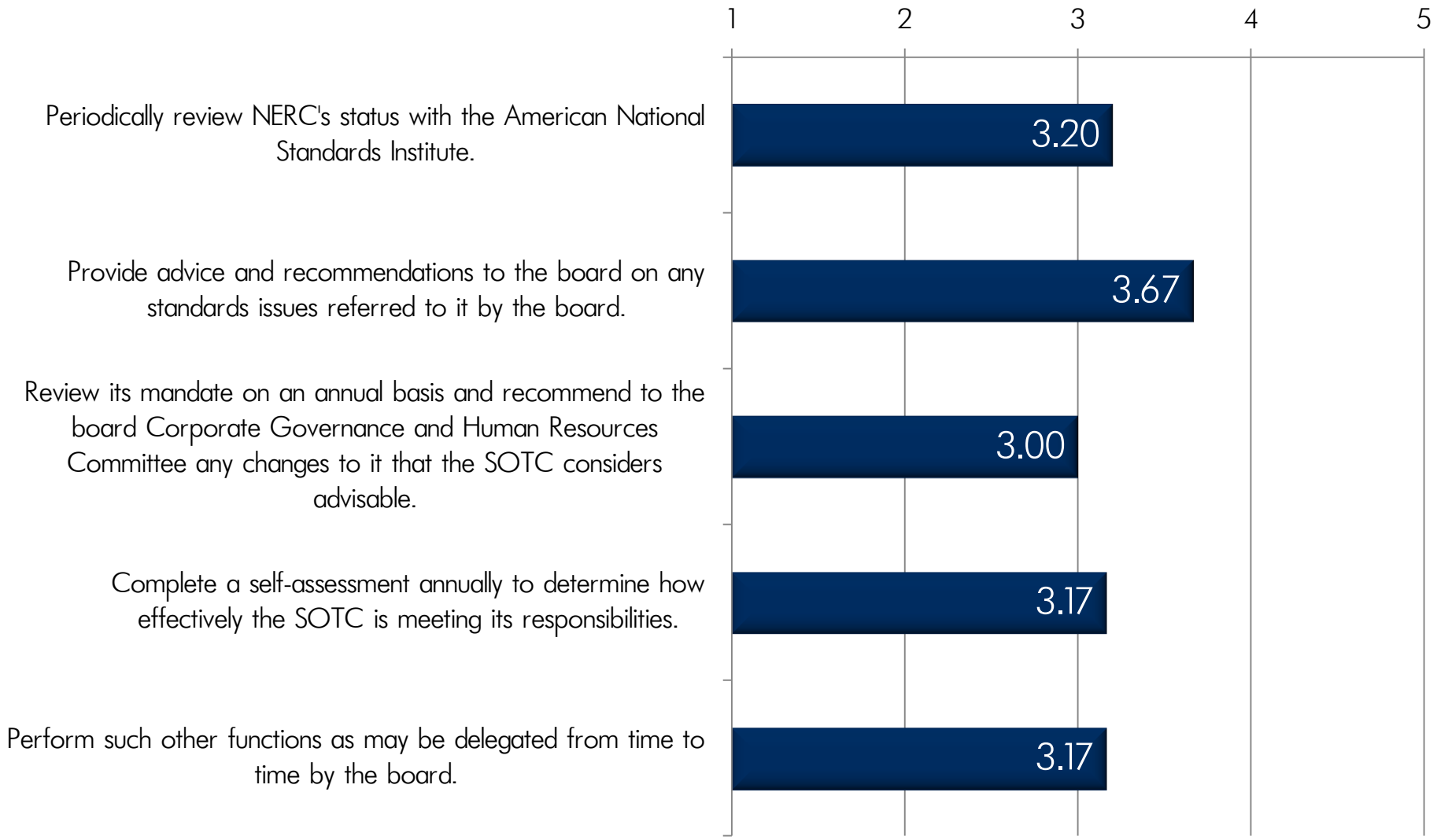
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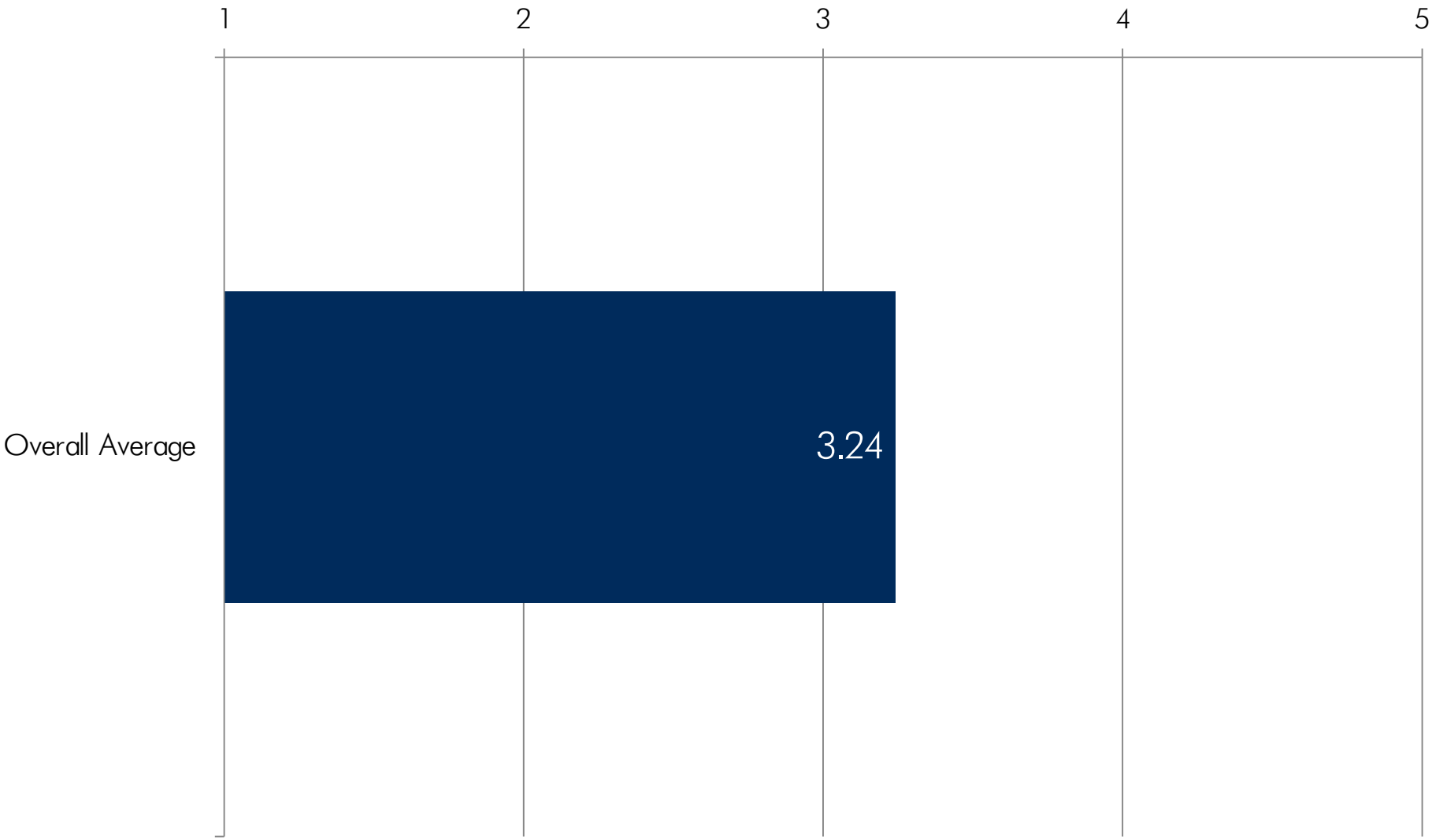


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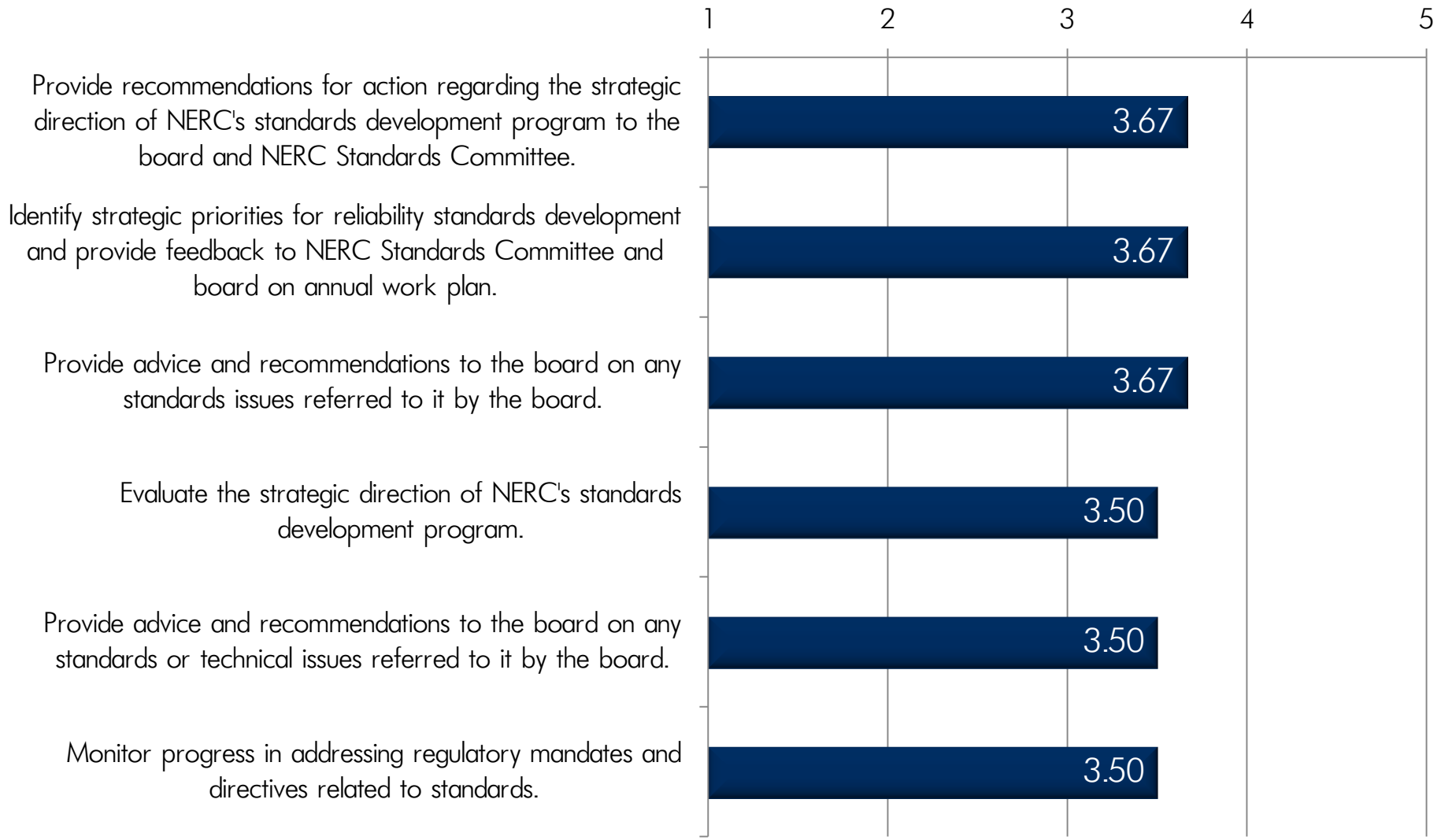
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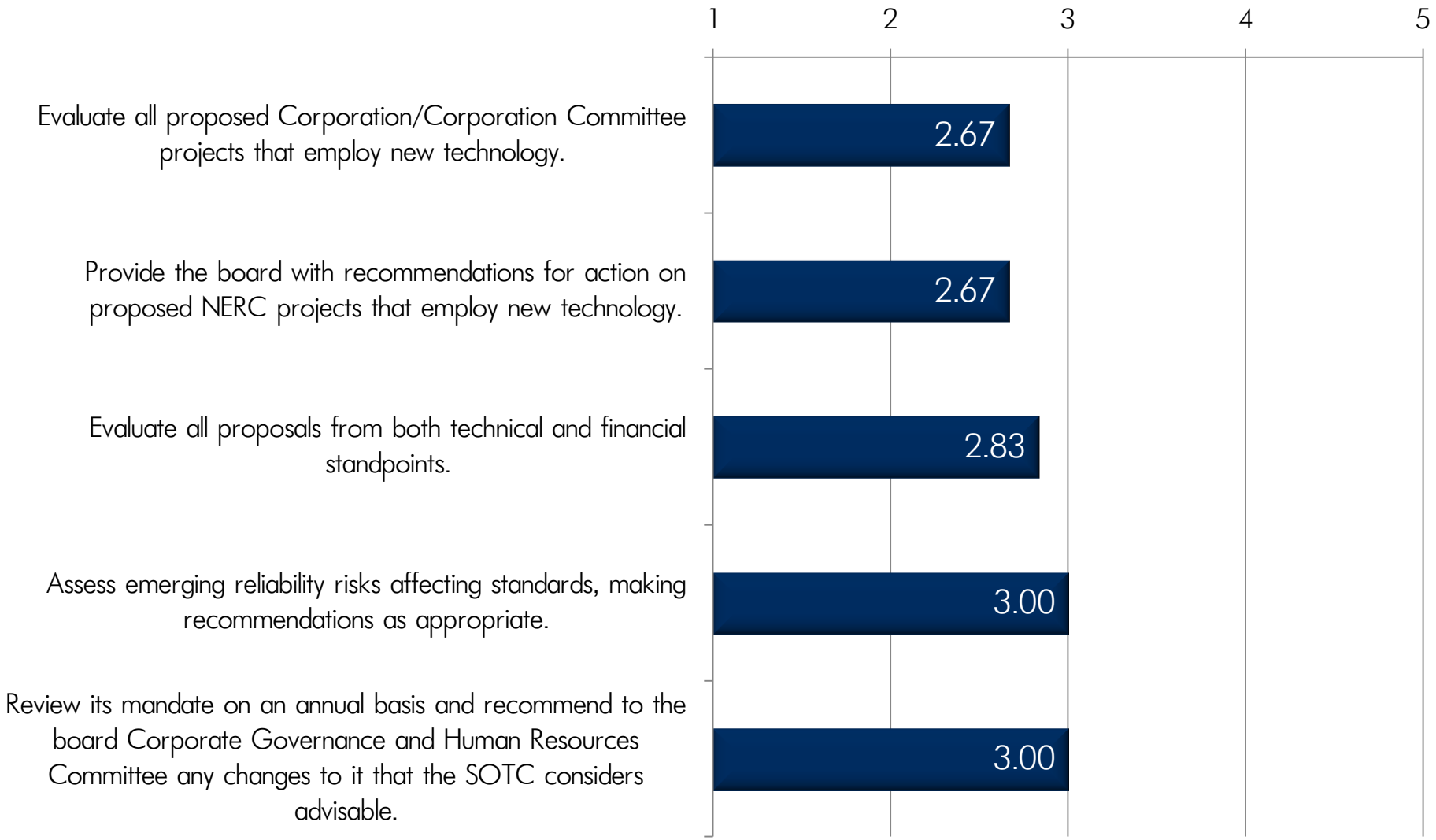
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SOTC Top Items



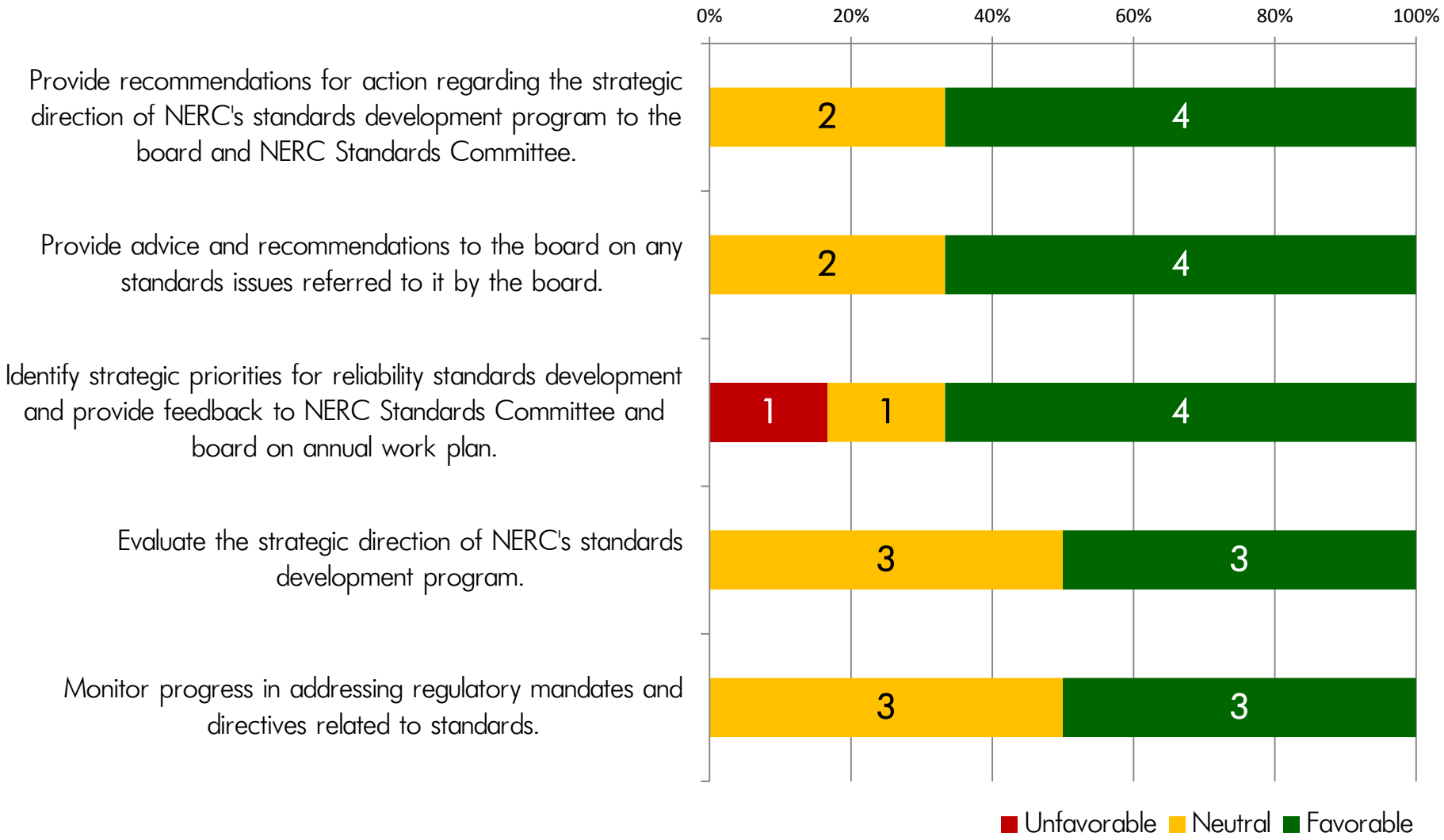
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SOTC Bottom Items



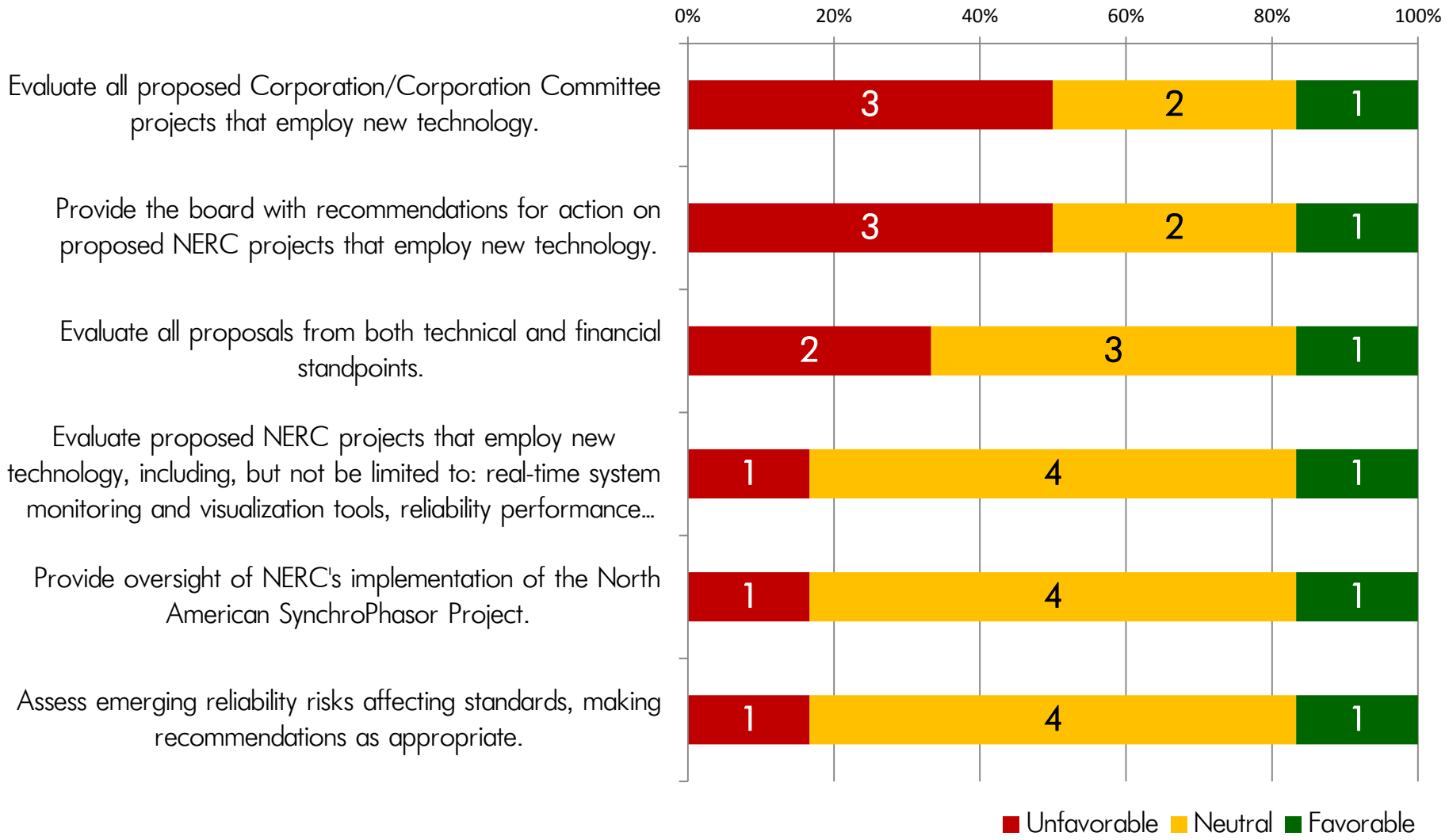
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SOTC Most Favorable



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SOTC Least Favorable



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COMMENTS

Comments (1 of 3)

- A very good start-up of the Standards oversight part of the mandate this year. The Committee will need to find the right role and balance over time to have influence, but not cramp the legitimate independence needed by the SC. Ken is really putting in the time and adding the intellectual energy needed to partner well with the SC and lead the Committee.

- SOTC is still learning and feeling its way in terms of roles and responsibilities in the Standards area. Focus on technology has diminished due to new Standards tasks and the change in leadership at NERC. 2012 should see a more robust engagement across the spectrum. However, major attention will continue to be paid to Standards as that is the area in most need of improvement ERO-wide.

Comments (2 of 3)

- SOTC stands ready to complete its mandate. Some areas of the mandate are active, and others not so. Review/oversight of the SC is a work in progress and is going as expected. We oversee the SC, respond when queried, and indicate the importance to the Board of quality standards being completed promptly. Regarding technology, not much to do other than monitoring the phasor project, which is going well. However, I suggest that NERC and SOTC should continue to be a catalyst for new technology ideas beneficial to reliability as it has in the past. IDC and other software platforms, and the phasor project are relevant examples. The next big game changer for reliability could well be "energy storage". and SOTC should be a voice to the Board and the industry to encourage "storage" ideas to come forward. We should be a catalyst and an incubator as needed. For the promising ideas, we should encourage the industry to carry them on to fruition.

Comments (3 of 3)

- Technology aspects are progressing well. The new standards oversight role is ramping up nicely under the strong leadership of the Chairman.

- The committee is still relatively new and as such it is finding its way to deal with the very broad mandate requirements; especially the technology topics on an in-depth basis.

- This is a new committee and is still in the early stage of understanding the full requirements for effective performance

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Agenda Item 3
SOTC Meeting
February 8, 2012

Information Technology Update

Standards Oversight and Technology Committee
February 8, 2012

RELIABILITY | ACCOUNTABILITY






Executive Summary

NERC Technology Update

- Key Accomplishments
  - Princeton to Atlanta Data Center
  - Washington DC office
  - Public-facing website
  - Process/stability
- NERC Information Technology Architecture Study
  - Key findings
  - Recommendations
- ERO Project Management Office Update
  - Accomplishments to date
  - Next steps
- Four Pillars – Information Technology Next Steps
  - Four Pillars – Information Technology Next Steps

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Technology Update

- Princeton to Atlanta Data Center move complete.
- Washington DC new office complete/on-time move in on December 16, 2011.
- Help Desk single point of contact (SPOC) established and implemented – follows Information Technology Infrastructure Library (ITIL) methodology.
- Implemented new Intranet site using SharePoint.
- NERC public-facing website assessment completed. Design and implementation plan created – estimated completion Q3/2012.
- Established NERC Information Technology Advisory Group (ITAG) – Senior leadership with the role of providing guidance and strategic direction on business priorities.
- Completed assessment of purchasing process for Microsoft licenses. Result: Enterprise Agreement (EA) signed that will provide consolidated license tracking, increased flexibility and an estimated 35 percent savings over the six-year agreement.
- Recommended and approved virtualization technology that will improve redundancy and stability of critical business systems.

NERC IT Architecture (ITA) Study

- IT Architecture (ITA) Study
  - Deloitte & Touche completed an ITA study for NERC from November 11, 2011 through January 23, 2012. The goal was to review and recommend steps to improve the technology infrastructure, resource alignment and process methodology for NERC Information Technology and Services.
  - Key Findings:
    - NERC Information Technology infrastructure (hardware, co-location, network) follow best practices for redundancy and stability.
    - NERC application review suggested improvements are required in order to seamlessly mine data across multiple disciplines, ex., Compliance, Standards, RAPA, etc., in order to have a holistic view of data.
    - NERC Information Technology has considerable work to achieve in order to align services with technology best practices and process methodology.
    - Several resource enhancements are required in order to build organizational structure aligned with ERO requirements for application and data needs.
    - NERC and the ERO Regional organizations must work together to align strategic application needs in order to maximize effectiveness.

Project Management Office Update

- ERO Project Management Office (PMO) Update
  - PMO staffed with three (3) resources: Manager, Project Manager, Jr. Business Analyst/Technical writer
  - Technical - Compliance Reporting and Tracking System (CRATS) identified as priority #1 by ERO EMG members as requiring immediate stabilization. Since November: WECC, TRE, MRO all synchronizing with no requirement for manual workbook submission. RFC targeted for end of February 2012
  - NERC Business Process Mapping for four processes: Alerts, FFT, Registration and Event Analysis
    - Next steps – Define process implementation plan for NERC specific improvement opportunities and work with the Regions to develop and implement improvements to ERO-wide processes

Project Management Office Update

- Process – Business requirements effort underway to document CRATS Enforcement process steps and target for immediate improvement. Target requirements completion – end of Q2/2012
- PMO next steps:
  - In conjunction with Information Technology, deploy extranet site for ERO visibility to project status
  - Develop and deploy agreed upon ERO process for application criteria, application submission, application prioritization (by ERO EMG) and resource and cost allocation
  - In collaboration with the ITSG members develop agreed upon:
    - Vendor criteria
    - ERO processes for data submission, security, policies, reporting and ongoing status updates
    - ERO processes for application acceptance testing, deployment and enhancement processes

Information Technology Next Steps

Next Steps: Build upon ERO Four Pillars



Reliability – to address real impacts and events, to improve the reliability of the grid
☑ Design - technology that is stable, business driven and secure



Accountability – to be accountable to customers, the industry, and government for the reliable performance of the grid
☑ Implement - metrics and Service Level Objectives for accountability



Learning – to continually improve and adapt to changes in the dynamic electric industry
☑ Operate - Continually improve our service focus and knowledge management



Risk-based – to focus resources and actions on issues most important to grid reliability
☑ Plan - Put plans in place to identify and mitigate risk to our mission

Agenda Item 4
SOTC Meeting
February 8, 2012

Reliability Standards
Policy and Guidance Items

Action
Discussion

Summary

a. Generator Operator (GO)/Transmission Operator (TO)

Background
Building on the work of the Ad Hoc Group for Generator Requirements at the Transmission Interface (Ad Hoc Group), these standards include modifications that help ensure that responsibility for generator interconnection facilities is appropriately assigned in NERC's Reliability Standards. The changes proposed by the drafting team for Project 2010-07 offer a focused approach whereby sole-use interconnection facilities (at or above 100 kV) that are owned and operated by generating entities will be included in a small set of standards and requirements previously only applicable to TOs. These generating entities (Generator Owners and Operators) do not own or operate facilities that are part of the interconnected system; rather, they own and operate sole-use facilities that are connected to the boundary of the interconnected system, and as such, may have a limited role in providing reliability compared to those entities that operate in a networked fashion beyond the point of interconnection.

With the above in mind, the drafting team for Project 2010-07 proposed the following standard modifications:

- FAC-001-1 now requires a GO to document and publish facility connection requirements if and when it executes an agreement to evaluate the reliability impact of interconnecting a third party facility to its existing generation interconnection facility.

  It is still rare for a third party facility to interconnect to an existing generator interconnection facility, but the scenario has occurred in the past (*see Alta Wind I LLC, et al.*, 134 FERC ¶ 61,109 at P 19 (2011) and *Sky River, LLC*, 134 FERC ¶ 61,064 at P 13 (2011)). Once that interconnection occurs, a GO may be registered for other functions (such as TO, Transmission Planner, and/or Transmission Service Provider), but until such additional registration occurs, there is no requirement for the GO to document and publish facility connection requirements.
- In PRC-004-2.1a, the phrasing of R2 ("The Generator Owner shall analyze its generator Protection System Misoperations…") could lead to some confusion about whether an interconnection facility is included. The phrase "…and generator interconnection Facility" was added as shown in the redlined version of the standard. Because there is no change in applicability, this change is considered a minor change employed only to add clarity.

Standard Development Process

FAC-001-1 progressed through the normal standards development process, which included three postings for stakeholder comment (one informal and two formal) over a nine-month period, an initial ballot in November 2011, and a recirculation ballot in December 2011. The changes made between comment periods improved the clarity of the applicability changes.

PRC-004-2.1a progressed through the normal standards development process, which included one formal comment period that began in October 2011, an initial ballot in November 2011, and a recirculation ballot in December 2011. The changes made between the ballots ensured that the phrase "…and generator interconnection Facility" was included in all necessary sections of the standard.

The ballot for Project 2010-07 closed on December 23, 2011 with the following results:

- FAC-001-1: quorum of 88.48 percent, approval of 90.10 percent
- PRC-004-2.1a: quorum of 86.65 percent, approval of 96.43 percent

FAC-003-3 – Transmission Vegetation Management, which adds GOs to the applicability section of FAC-003-2,[1] was also modified as a part of Project 2010-07. This standard was balloted along with FAC-001-1 and PRC-004-2.1a and was approved by stakeholders (with an 87.17 percent quorum and an 85.38 percent approval). However, a Level 1 Appeal of FAC-003-3/FAC-003-X was received on January 20, 2012 and is pending. Accordingly, the request for Board of Trustees action (if any) relative to FAC-003-3 is being held until the appeal process can be completed. The Level I appeal is attached.

There has been discussion in the industry regarding the need for additional standards to be addressed in order to deal with generator interface issues.

[1] FAC-003-2 was developed as part of Project 2007-07 and approved by the Board of Trustees on November 3, 2011.

b. COM-002 Interpretation

Background

On October 1, 2009, a clarification was requested by the ISO-RTO Council of Requirement R2 of COM-002-2, specifically asking whether "directives" are limited to actions requested during actual and anticipated emergency operating conditions, or whether routine operating instructions are also considered "directives."

The initiation of the project for developing the interpretation was delayed following discussion with the requester based on the anticipation that more clarity regarding the term, "directives" would be provided through standard development work in Project 2007-02 Operating Personnel Communications Protocols (Project 2007-02). When it became clear that the work in Project 2007-02 would require considerable industry debate, an interpretation drafting team was formed and prepared a draft interpretation, which was posted for a 30-day formal comment period that ended December 18, 2010. However, work on the interpretation was further delayed based on reprioritization of the total standards workload, and again as the Standards Committee developed more formal processes for addressing interpretations.

In April 2011, the Standards Committee approved and issued the NERC Guidelines for Interpretation Drafting Teams and directed that work resume on the interpretation. At that time, the standards staff and the Standards Committee planned to work simultaneously on both the interpretation and Project 2007-02, with the goal of comprehensively addressing three part communication. However, On August 30, 2011 the Standards Review Committee of the ISO/RTO Council submitted a Level 1 Appeal for Inaction related to Project 2009-22 to the Vice President and Director of Standards. The Appeal requested that Project 2009-22 be given an "immediate/urgent" priority and be addressed within 30 days of receiving the Appeal, and that NERC provide a formal explanation of the delays associated with the Project. To be responsive to the Appeal, the interpretation was moved forward separately from the effort to develop a more comprehensive requirement for three part communication. The Appeal, as well as NERC's Response, is posted on the NERC website.

Results

A revised interpretation was posted for industry comment on October 10, 2011, with a parallel ballot conducted November 8–18, 2011. The ballot achieved a 95.05 percent approval, with a quorum of 91.2 percent. A recirculation ballot was conducted December 14–23, 2011, and the interpretation was approved by stakeholders, achieving a 94.58 percent approval with a quorum of 92.00 percent.

As described in the Standards Committee's *Roles and Responsibilities* document (page 8), NERC staff is "encouraged to provide comments during the standards development process." In addition to the technical comments submitted by NERC staff, NERC's functional area leaders submitted a letter to the Interpretation Drafting Team, highlighting key issues and concerns regarding three part communication.

January 20, 2012

Mr. Herb Schrayshuen
Vice President of Standards and Training
North American Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326

RE: Exelon Appeal of FAC-003-3 and FAC-003-X Process

Dear Herb:

Exelon wishes to initiate a Level 1 Appeal of the recent vote on FAC-003-3 (December 1, 2011 draft) and FAC-003-X (December 1, 2011 draft), Transmission Vegetation Management Program, as part of Project 2010-07, Generator Requirements at the Transmission Interface. Exelon believes that the NERC Standards Process Manual was not followed, and that based on the substantive changes made to both Standards following the Initial Ballot, NERC should have set the Standards for vote using a Successive Ballot rather than a Recirculation Ballot.

Exelon voted against these proposed Standards, and while we respect the vote of the Ballot Body, we believe that the manner in which the Standards were presented for vote is contrary to the process required by the NERC Standards Process Manual.

Prior to the Recirculation Ballot, Section 4.3.1, which defines the criteria for determining which Generation Owners will be covered by the Standards, was modified to increase the scope and applicability to generator owned overhead transmission lines by adding the words "or do not have a clear line of sight from the switchyard fence to the point of interconnection." FAC-003-3; see also FAC-003-X.[1] The Standard Drafting Team's ("SDT") explanation for this last minute addition to Section 4.3.1 is that the addition of the "line of sight reference" merely clarifies the "exception language based on the intent that was agreed upon by the stakeholder body." Sidebar comments to Sections 4.3.1 of FAC-003-3 and FAC-003-X. The SDT went on to identify the "intent" of the stakeholder body as follows:

[1] The language in Section 4.3.1 of FAC-003-3 and FAC-003-X is similar, but not identical. (Compare Section 4.3.1 in FAC-003-3 (quoted in body of this letter) to FAC-003-X, which reads "or does not have a clear line of sight from the switchyard fence to the point of interconnection. . . .")) With respect to the language at issue in this appeal, the differences are of no consequence. Accordingly, references to Section 4.3.1 refer collectively to Section 4.3.1 of FAC-003-3 and FAC-003-X.

> "'We believe that the one mile length is a reasonable approximation of line of sight, and that using a fixed starting point (at the fenced area of the generation station switchyard) eliminates confusion and any discretion on the part of a Generator Owner or an auditor.' With the addition of an explicit line of sight reference here, the SDT believes it has clarified its original intent."[2]

This explanation does nothing more than (1) reiterate the point the SDT has maintained throughout the entire drafting process, namely that "the one mile length" of a transmission line "is a reasonable approximation of line of sight," and (2) explain that the SDT included a "fixed starting point" (the fenced area of the generation station switchyard) from which to measure the line to address stakeholder concerns about excessive Generator Owner discretion and inconsistent application of the Standard. The stakeholder concerns and the SDT's response have absolutely nothing to do with – and certainly do not express the "intent that has been agreed upon by the stakeholder body" – the inclusion of "or do not have a clear line of sight from the switchyard fence to the point of interconnection." To be clear, the SDT, and even the Ad Hoc Group prior to the SDT, have always focused on the length of the transmission line (either a half mile as proposed by the Ad Hoc Group or a mile as proposed by the SDT) as the basis for determining coverage, the presumption being that up to a certain distance, the overhead line is in the line of sight at various locations throughout the Generator Owner's property and reasonably subject to being managed through normal day-to-day plant activities. The SDT has not, until the most recent iteration of the Standards, focused on requiring a "clear" line of sight to "the point of interconnection." The requirement that the Generator Owner be able to view the "point of interconnection" while standing at the switchyard fence is a wholly new requirement based on new considerations not previously addressed through stakeholder comments.

A review of the Technical Justification Document,[3] apparently developed prior to the Initial Ballot (referred to as the "Initial Technical Justification") supports Exelon's position. In that document, the SDT refers to the Ad Hoc Group's original thought to exclude from the Standard any transmission lines that was "less than two spans [long] (generally one half mile from the generator property line)."[4] The SDT then explained that, "[a]fter reviewing formal comments, the SDT agreed to revise the exclusion so that it applies to a Facility [transmission line] if its length is 'one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard' to approximate line of sign [sic] from a fixed

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[2] Standard FAC-003-X at p. 2 (Draft 3: Dec. 1, 2011); Standard FAC-003-3 at p. 6 (Draft 3: Dec. 1, 2011)

[3] From the title, "Technical Justification Project 2010-07 Generator Requirements at the Transmission Interface," it appears that the document was created on September 30, 2011, although it appears that the PDF version was created on October 4, 2011. 2011_09_30_Technical_Justification_Document.pdf. In either case, this means the document was codified prior to the start of the November 9, 2011 Initial Ballot.

[4] 2011_09_30_Technical_Justification_Document.pdf at p. 3.

point,"[5] (the fixed point being the fenced area of the generating station switchyard). Importantly, the Ad Hoc Group and SDT focused on the length of the line, with no discussion or evaluation of requiring a "clear" line of sight from the fence "to the point of interconnection."

Aside from the fact that the last minute change by the SDT does not reflect stakeholder intent, it is also technically unsupported. The SDT just added the requirement for a "clear" line of sight "to the point of interconnection" language without considering the implications of why such a change was required. While a specific fixed point may make sense for establishing a starting point from which to measure distance (the one-mile limitation), it does not when considering a clear line of sight, especially in light stakeholder comments and the SDT's acknowledgment that

> in many case, generation Facilities are either (1) **staffed and the overhead portion is within the line of sight** or (2) the overhead Facility is over a paved surface. Stakeholders have generally supported the rationale exempting these Facilities because incorporating them into FAC-003 would offer no reliability benefit. The SDT and industry comments support the position that these qualifiers represent a reasonable and appropriate risk prevention approach.[6]

Notably absent from this rationale is any requirement that there be a clear line of sight from a fixed point; nor is a clear line of sight required when the distance of the overhead line is short (less than a mile) and the Facilities are staffed on a daily basis, meaning that the overhead line will be subject to observation by staff, even if the staff does not have a clear line of sight from a specified fixed point (the switchyard fence) to the point of interconnection. An example helps illustrate this point. Some Generator Owner transmission lines come out of the generating station and take a 'dog leg' turn (the line turns at one of the towers). Standing at the tower, an individual has a clear line of sight to either end of the line (the end coming out of the station and the end connecting with the point of interconnection). Since the generating Facility is staffed and the line is within the Generator Owner's property line or controlled area, the line can be observed and maintained by staff in the same manner as any other short distance line with a "clear" line of sight from the switchyard fence to the point of interconnection.

As illustrated by the preceding discussion, the SDT's last minute addition of "or do not have a clear line of sight from the switchyard fence to the point of interconnection" constitutes a material and significant change in the scope of the applicability of the Standards to Generator Owners, and it was inappropriate for NERC to use a Recirculation Ballot. The Standard Process Manual regarding Recirculation Ballots (pages 19-20) states:

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[5] 2011_09_30_Technical_Justification_Document.pdf at p. 3.

[6] Consideration of Comments Generator Requirements at the Transmission Interface Project 2010-07, p. 1 (emphasis added).

Conduct Recirculation (Final) Ballot
(Standard has not Changed Substantively from Prior Ballot)

When the drafting team has reached a point where it has made a good faith effort at resolving applicable objections, the team shall conduct a recirculation ballot. In the recirculation ballot, members of the ballot pool shall again be presented the proposed standard **(that has not been significantly changed from the previous ballot)** along with the reasons for negative votes, the responses, and any resolution of the differences**. An insignificant revision is a revision that does not change the scope, applicability, or intent of any requirement and includes but is not limited to things such as correcting the numbering of a requirement, correcting the spelling of a word, adding an obviously missing word, or rephrasing a requirement for improved clarity.** Where there is a question as to whether a proposed modification is "substantive" the Standards Committee shall make the final determination. There is no formal comment period concurrent with the recirculation ballot and no obligation for the drafting team to respond to any comments submitted during the recirculation ballot.

(Emphasis added.)

Regardless of whether the SDT believed that its addition of the language at issue here clarified the intent of the stakeholder body, using the Recirculation Ballot for the Standards was not warranted or allowed by process. An unarticulated intent of the stakeholder body cannot serve as the basis for a substantive change to the Standard. More importantly, the language added by the SDT clearly changed the scope and applicability of the Standard, by drawing in Generator Owners that would have otherwise been excluded from the Standards, namely those Generator Owners with transmission lines less than a mile long that will now be covered by the Standard because some shorter distance of its line is not clearly visible from the switchyard fence to the point of interconnection. The SDT's presentment of this change through a Recirculation Ballot deprived Exelon (and possibly others) of having its comments considered by the SDT and the SDT answer on the record for consideration by the Ballot Body in accordance with the requirements of a Successive Ballot. You can read Exelon's comments on the Recirculation Ballot at:

https://standards.nerc.net/VoterComment.aspx?VoteGUID=8801b661-a474-4f54-b14a-4cfe644bdaa6.

Please let me know if you have any further questions.

Best regards,



Steven T. Naumann
Vice President, Wholesale Market Development
Federal Regulatory Affairs & Public Policy, Exelon Corporation

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Agenda Item 5
SOTC Meeting
February 8, 2012

Reliability Standards Status Report

Standards Oversight and Technology Committee Meeting

February 8, 2012

RELIABILITY | ACCOUNTABILITY






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Regional Standards and Variances filed by NERC with FERC: 1

Regional Standards and Variances approved by Regional Entity Board (not included above): 1

Regional Standards Activities and Accomplishments-2011: 1

Accomplishments 1

Other Activities 2

Future Regional Standards 2012 1

Standards Development Forecast (Continent-wide)

Standards

Projects forecast for action at the May 2012 Board of Trustees meeting

- 2007-03 Real-time Operations (April 25)[1]
- 2007-12 Frequency Response (May 10)

Projects forecast for action at the August 2012 Board of Trustees meeting

- 2006-06 Reliability Coordination (remainder)[1]
- 2007-17 Protection System Maintenance and Testing
- 2008-06 Cyber Security Order 706
- 2009-01 Disturbance and Sabotage Reporting[2]

Projects forecast for action at the November 2012 Board of Trustees meeting

- 2007-09 Generator Verification (partial; remainder February 2013)[1]
- 2010-14.1 Phase 1 of Balancing Authority Reliability-Based Controls: Reserves (partial; remainder February 2013)[3]
- 2010-05.1 Phase 1 of Protection Systems: Misoperations

Projects forecast for action at the February 2013 Board of Trustees meeting

- 2010-14.1 Phase 1 of Balancing Authority Reliability-Based Controls: Reserves (remainder)
- 2010-07 Generator Verification (remainder)

Interpretations

Four interpretations, including two CIP interpretations and two non-CIP interpretations that are being addressed through a rapid revision of the standard, are expected to require action at the August 2012 Board of Trustees meeting.

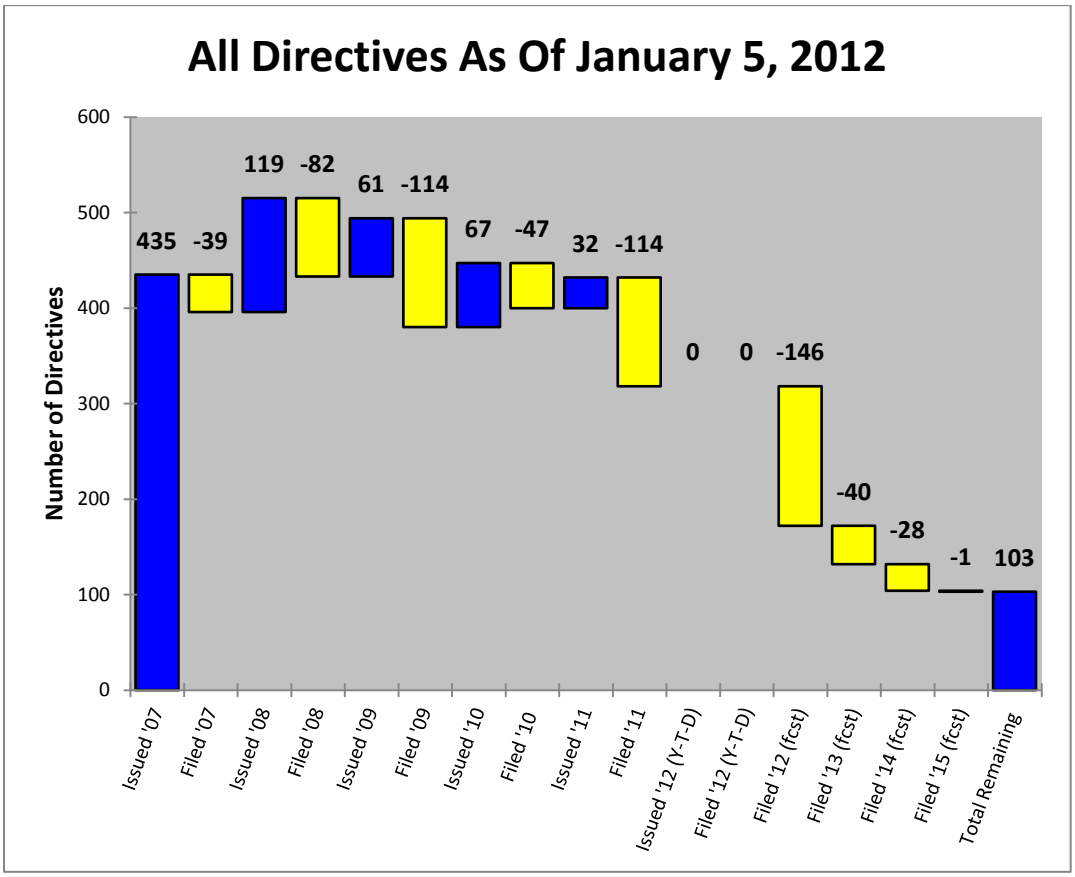
[1] This project has been intentionally delayed in order to limit the number of concurrent standards actions being requested of industry stakeholders.
[2] This project has been intentionally delayed due to a need to hold a Successive Ballot following an unsuccessful Initial Ballot.
[3] Part of this project has been delayed based on a Standards Committee request to schedule a Successive Ballot to mitigate the risk of an unsuccessful Initial Ballot

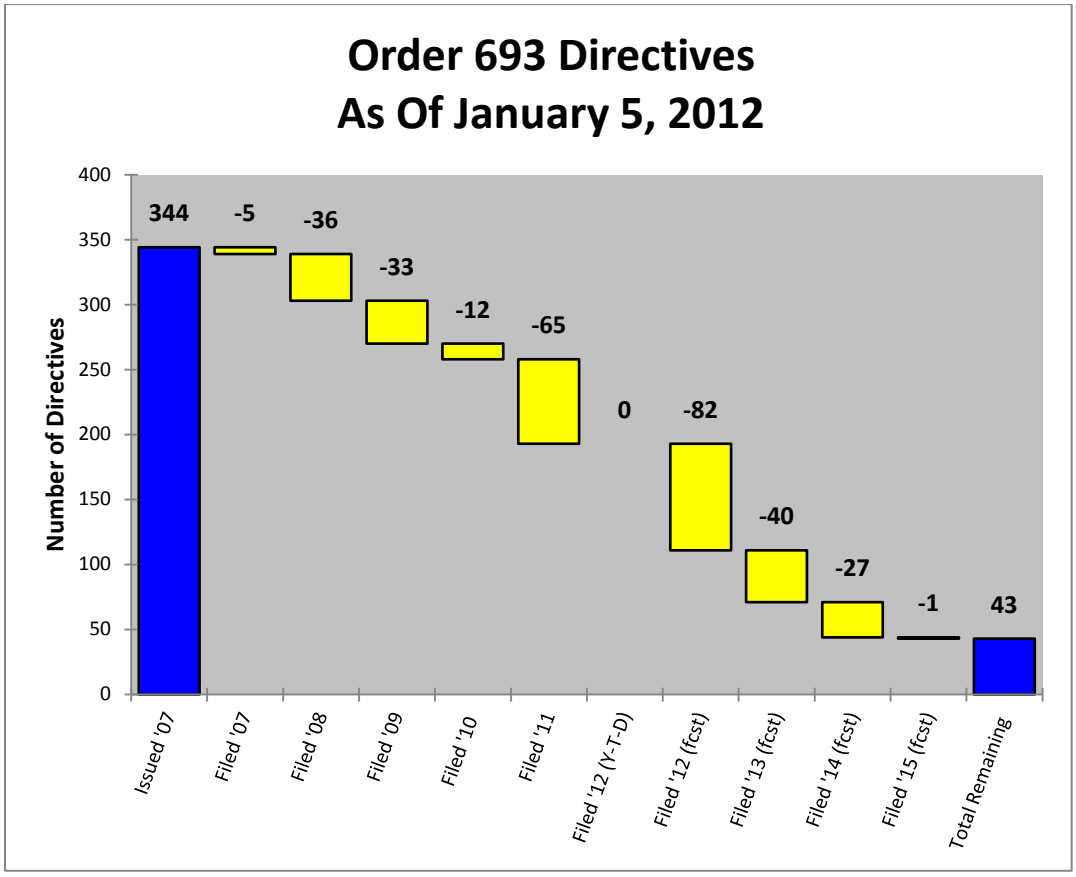
Outstanding Regulatory Directives-Update

Regulatory Directives Update

The Standards staff continues to coordinate with FERC staff on identification of FERC regulatory directives focused on standards development. The last quarter of 2011 focused on the directives associated with cyber security. More work is needed to be completed associated with the NERC-FERC directives coordination effort. The goal is to complete the coordination effort on or before March 31, 2012, so that NERC can submit to FERC the status and timetable for addressing each outstanding directive, consistent with Rule 321 of NERC's Rules of Procedure.

The following charts summarize the progress on responding to standards-related directives to date.





Additional changes to the "directive counts" are expected to continue based on the coordination effort between FERC and NERC staffs until the directives report is prepared in the first quarter of 2012.

Regional Standards Group February 2012 Report

This report highlights the key activities of NERC and the Regions in support of the Regional Standards Group (RSG) charter obligations in the year 2011.

The RSG met on a monthly basis and held 12 meetings this year in-person or by phone.

The regions have worked to perform quality reviews, post regional standards to the NERC website, and file regional standards and variances with FERC. As a result of these efforts we report the following.

Regional Standards –2011

Regional Standards and Variances filed by NERC with FERC:

- PRC-002-NPCC-01 (approved by FERC on October 20, 2011)
- CIP-001-2a (TRE regional variance to CIP-001 – Sabotage Reporting) (approved by FERC on August 2, 2011)
- IRO-006-TRE-01
- PRC-006-SERC-01

Regional Standards and Variances approved by Regional Entity Board (not included above):

- PRC-006-NPCC-01
- MOD-25-RFC-01 (ReliabilityFirst has requested NERC staff to delay filing this standard with FERC until a ReliabilityFirst Board directed evaluation of the need for regional standards is completed)

Regional Standards Activities and Accomplishments-2011

Accomplishments

- Seven of the eight Regional Standards development projects provided milestones for coordination of processing purposes to NERC.
- NERC Regional Standards staff has:
  - Prepared a unified schedule for all regional projects in development (see attached)
  - Processed six regional postings for comment on behalf of the regions
  - Performed 11 quality reviews on Regional Standards and variances
  - Attended 13 Regional Standards Development team meetings (in-person or by phone) for coordination purposes

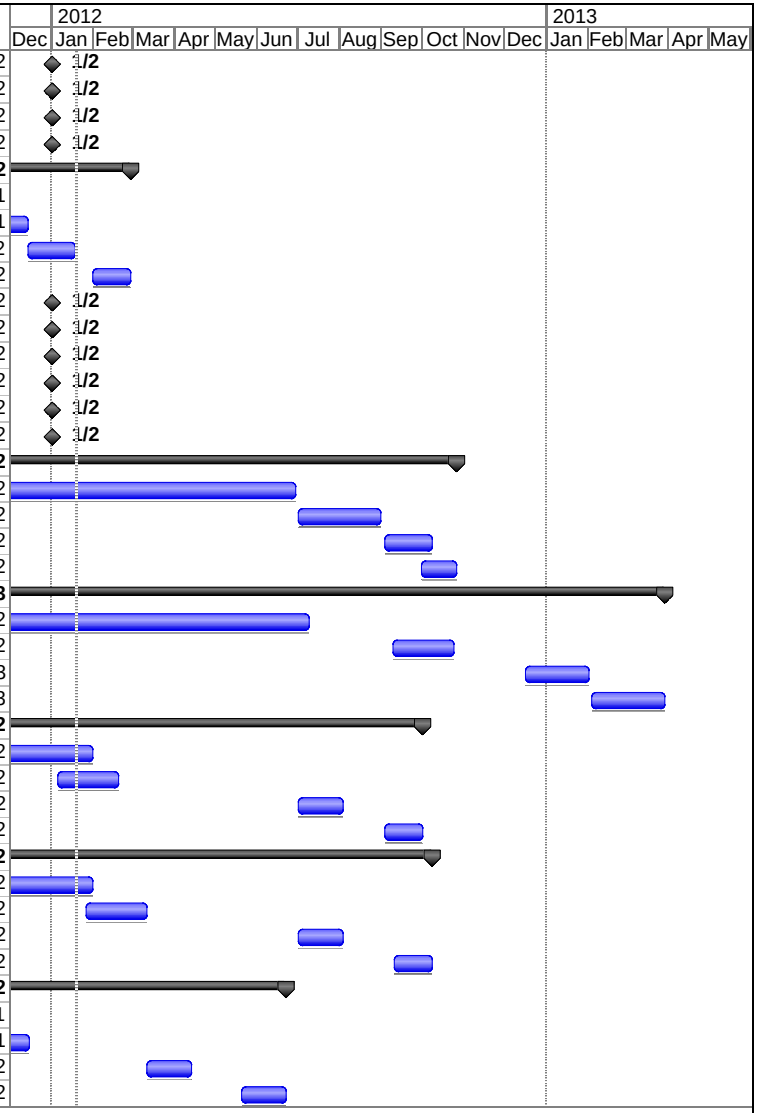
- Attended 6 Regional Standard Committee meetings on-site for coordination purposes
- Updated the NERC Regional Reliability Standards Under Development webpage
- Prepared a white paper on a comparison of regional standards, regional variances and regional procedures

Other Activities

- NPCC developed a Cost Effectiveness Analysis Procedure (CEAP), which was used in the NPCC Board evaluation of PRC-006-NPCC-01
- SERC revised their Regional Standards Development Procedure – to be presented at the February 2012 Board of Trustees meeting
- RFC proposed revised standard development procedures which were approved for filing with FERC by the Board of Trustees. Subsequent to Board of Trustees approval, RFC requested the filing with FERC be held pending additional changes requested by RFC stakeholders.
- WECC revised their Reliability Standards Development Procedure.

Future Regional Standards 2012 (see table on next page)

ID	Task Name	Duration	Start	Finish
1	**PRC-002-FRCC-1 (on hold)**	0 days	Mon 1/2/12	Mon 1/2/12
2	**PRC-003-FRCC-1 (on hold)**	0 days	Mon 1/2/12	Mon 1/2/12
3	**PRC-006-FRCC-1 (on hold)**	0 days	Mon 1/2/12	Mon 1/2/12
4	**PRC-024-FRCC-1 (on hold)**	0 days	Mon 1/2/12	Mon 1/2/12
5	**PRC-006-NPCC-1**	**917 days**	**Mon 8/25/08**	**Tue 2/28/12**
6	Regional standard development	805 days	Mon 8/25/08	Fri 9/23/11
7	Posting of Documents for process evaluation at NERC	45 edays	Mon 10/31/11	Thu 12/15/11
8	Prepare BOT Material	25 days	Thu 12/15/11	Wed 1/18/12
9	Develop Initial Draft of Regulatory Filings	20 days	Wed 2/1/12	Tue 2/28/12
10	**PRC-012-NPCC-1 (on hold)**	0 days	Mon 1/2/12	Mon 1/2/12
11	**MOD-024-RFC-01 (on hold)**	0 days	Mon 1/2/12	Mon 1/2/12
12	**MOD-025-RFC-01 (on hold)**	0 days	Mon 1/2/12	Mon 1/2/12
13	**PRC-002-RFC-01 (on hold)**	0 days	Mon 1/2/12	Mon 1/2/12
14	**PRC-006-RFC-1 (on hold)**	0 days	Mon 1/2/12	Mon 1/2/12
15	**PRC-012-RFC-1 (on hold)**	0 days	Mon 1/2/12	Mon 1/2/12
16	**PRC-006-SPP-01**	**1302 days**	**Thu 11/1/07**	**Fri 10/26/12**
17	Regional standard development	1217 days	Thu 11/1/07	Fri 6/29/12
18	Posting of Documents for process evaluation at NERC	45 days	Mon 7/2/12	Fri 8/31/12
19	Prepare BOT Material	25 days	Tue 9/4/12	Mon 10/8/12
20	Develop Initial Draft of Regulatory Filings	20 days	Mon 10/1/12	Fri 10/26/12
21	**BAL-001-TRE-1**	**666 days**	**Fri 9/10/10**	**Fri 3/29/13**
22	Regional standard development	68.38 edays	Fri 9/10/10	Mon 7/9/12
23	Posting of Documents for process evaluation at NERC	45 edays	Mon 9/10/12	Thu 10/25/12
24	Prepare BOT Material	35 days	Mon 12/17/12	Fri 2/1/13
25	Develop Initial Draft of Regulatory Filings	40 days	Mon 2/4/13	Fri 3/29/13
26	**BAL-002-WECC-1**	**472 days**	**Fri 12/10/10**	**Mon 10/1/12**
27	Regional standard development	298 days	Fri 12/10/10	Tue 1/31/12
28	Posting of Documents for process evaluation at NERC	45 edays	Fri 1/6/12	Mon 2/20/12
29	Prepare BOT Material	25 days	Mon 7/2/12	Fri 8/3/12
30	Develop Initial Draft of Regulatory Filings	20 days	Tue 9/4/12	Mon 10/1/12
31	**BAL-004-WECC-1**	**477 days**	**Fri 12/10/10**	**Mon 10/8/12**
32	Regional standard development	298 days	Fri 12/10/10	Tue 1/31/12
33	Posting of Documents for process evaluation at NERC	45 edays	Fri 1/27/12	Mon 3/12/12
34	Prepare BOT Material	25 days	Mon 7/2/12	Fri 8/3/12
35	Develop Initial Draft of Regulatory Filings	20 days	Tue 9/11/12	Mon 10/8/12
36	**VAR-001-WECC-1**	**442 days**	**Thu 10/14/10**	**Fri 6/22/12**
37	Regional standard development	180 days	Thu 10/14/10	Wed 6/22/11
38	Posting of Documents for process evaluation at NERC	45 edays	Tue 11/1/11	Fri 12/16/11
39	Prepare BOT Material	25 days	Mon 3/12/12	Fri 4/13/12
40	Develop Initial Draft of Regulatory Filings	25 days	Mon 5/21/12	Fri 6/22/12



Project: Unified Regional Project Sche
Date: Thu 1/19/12

Task
Split
Progress
Milestone
Summary
Project Summary
External Tasks
External Milestone
Deadline

Agenda Item 6
SOTC Meeting
February 8, 2012

Standards Committee Report

Since the last Board of Trustees meeting, the Standards Committee (SC) has met by conference call on November 10 and December 7 and is scheduled to meet in person on January 11-12, 2012. SC meeting agendas and minutes are posted at: http://www.nerc.com/filez/scmin.html

This report outlines major ongoing activities and policy issues under consideration by the SC and its subcommittees that may be of interest to the Standards Oversight and Technology Committee.

Key Issues Discussed During Joint meeting with CCC on December 7, 2011:

The SC had a joint meeting with the Compliance and Certification Committee (CCC) on December 7, 2011 and identified the following opportunities for future joint activities:

- Involve drafting teams in the development of reliability standard audit worksheets (RSAWs) with a possibility of eventually eliminating measures from standards
- Commitment to provide the compliance program with support in prioritizing its list of Compliance Application Notices (CANs) proposed for future development
- Continued support of the proposal to replace violation risk factors (VRFs) with an objective scoring system and with the proposal to replace violation severity levels (VSLs) with a set of pro forma VSLs

During the January 11-12, meeting, the SC made forward movement on the following:

- **Revisions to Standard Development Process**
  The SC is reviewing the standard development process and identifying ways of shortening the process without losing ANSI accreditation. Potential ideas already identified by staff for SC discussion include:
  - Use technical subject matter experts to serve as panelists to provide technical input on a standard, but have a team of interviewers (legal, technical writer, compliance) capture that information and develop a draft standard. The technical experts then review the standard to determine if it is technically accurate; each requirement achieves its reliability objective; the collection of requirements meets the standard's purpose.
  - Use stakeholder groups to provide preliminary informal feedback on a standard before it is publicly posted – so that the standard is 90 percent correct before its first public comment period.
  - Establish a one-year schedule for projects; five months to develop the initial draft and collect informal feedback to bring the standard to the 90 percent acceptance level; seven months to conduct required balloting and formal consensus building.
  - Replace the Registered Ballot Body (now over 1,000 members) with "delegates" that represent industry segments. Use delegates for collection and organization of comments and balloting. Stakeholders would continue to have the right to submit individual comments during public postings.

- **Triage Process for Determining How to Respond to Lessons Learned/Emerging Issues**
  The SC is drafting a process for reviewing information from analyses of events and emerging issues and determining what the ERO enterprise (including the SC and leaders of other committees and stakeholder groups) should do with that information to minimize risk to reliability. In some instances, the information gleaned from an event may lead to an alert, in other instances the response to an emerging issue may result in the development of a standard, guideline, training program, reference document or another product.
- **Rapid Revision Process**
  The SC field tested a rapid revision process that provides a revision to a standard as an alternative response to a request for an interpretation of an approved standard. The initial field test resulted in a permanent revision to the standard approved by its ballot pool in less than 90 calendar days from initial posting through completion of the recirculation ballot. The lessons learned from the field test will be used to document the process for future use.

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February 2011 Cold Snap Event Recommendations

January 23, 2011

Earl Shockley, Director of Reliability Risk Management

RELIABILITY | ACCOUNTABILITY






Recommendations - Electric

- February 1-5, 2011 event occurred
- August 15, 2011 – joint report released
- There were a total of 26 electric recommendations issued:
  - Planning and reserves (5);
  - Coordination with generator owners/operators (5);
  - Winterization (10);
  - Communications (4); and
  - Load Shedding (2)
- There were also six gas recommendations

Theme -Three "P's"

- August 2003 Blackout delivered three distinct themes called the three "T's".
  - Trees
  - Tools
  - Training
- The February 2011 Cold Snap event delivered three distinct themes
  - Predict
  - Planning
  - Preparation

First P – "Predict"

- The storm was not without precedent. There were prior severe cold weather events in the Southwest in 1983, 1989, 2003, 2006, 2008, and 2010.
  - Good **analyses** were conducted
  - Good **reports** were written
  - Good **recommendations** were developed
  - **No** institutionalization of the recommendations and lessons

Can we now predict the same circumstances?

Second P – "Planning"

- On site visits with GO/GOPs revealed:
  - Some plants had inadequate plans and safeguards in place to address severe weather.
    - Lack of formal plans, procedures to address severe weather
    - Lack of adequate knowledge of plant temperature design limits and the equipment most effected by freezing
    - Failure to adequately apply and institutionalize knowledge and recommendations from previous severe winter weather events
  - Some plants had rigorous plans and safeguards in place, some required validation.

Can you predict which plants were most successful during the event?

Preparation

Third P – "Preparation"

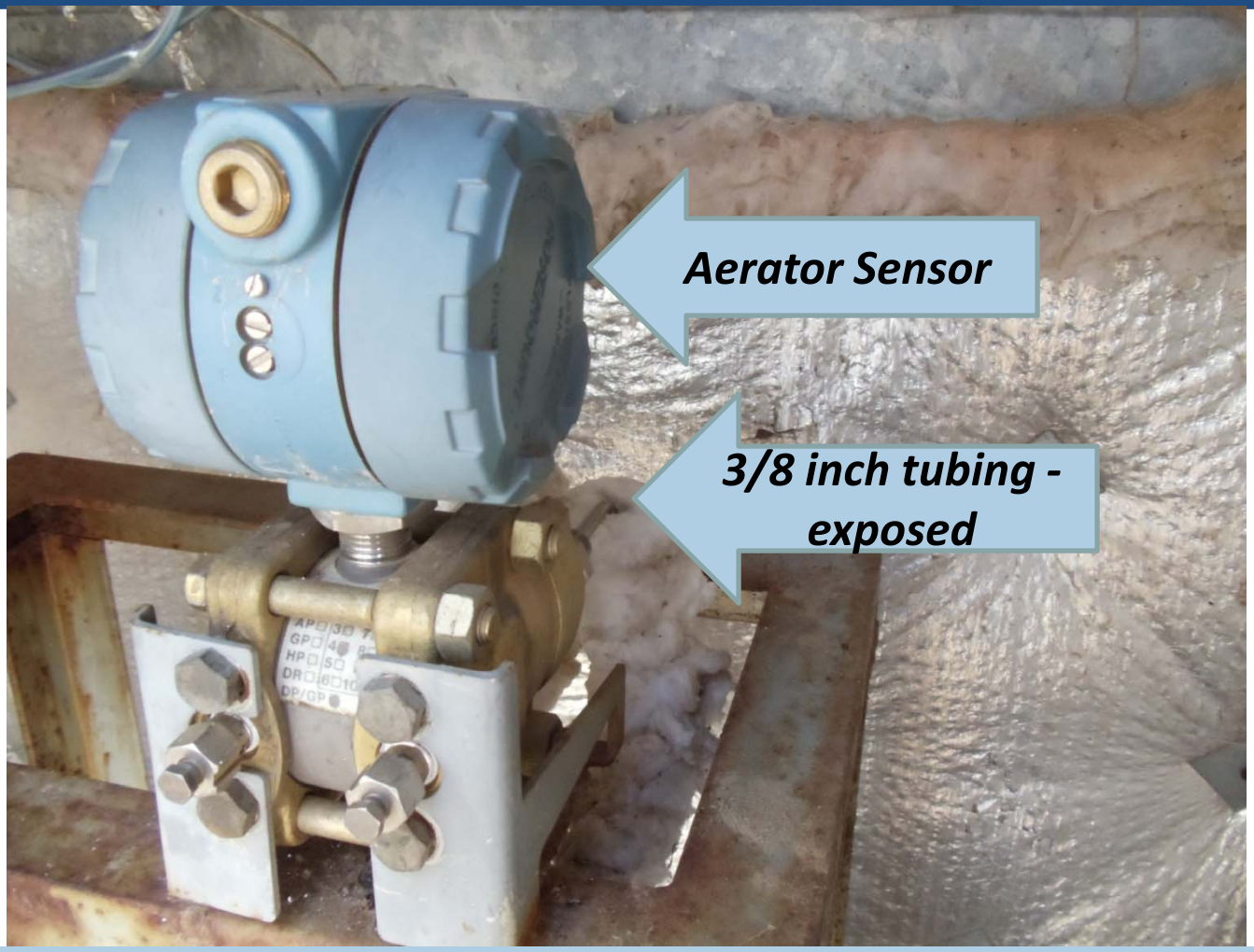
- Generators were generally reactive as opposed to being proactive in their approach to winterization and preparedness. Many generators failed to adequately prepare for winter, including the following:
  - Failed or inadequate heat traces,
  - Missing or inadequate wind breaks
  - Inadequate or lack of insulation
  - Failure to have or to maintain heating elements and heat lamps in instrument cabinets
  - Failure to have necessary resources and supplies

BY FAILING TO PREPARE, YOU ARE PREPARING TO FAIL.

BENJAMIN FRANKLIN

NERC
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Frozen Sensor



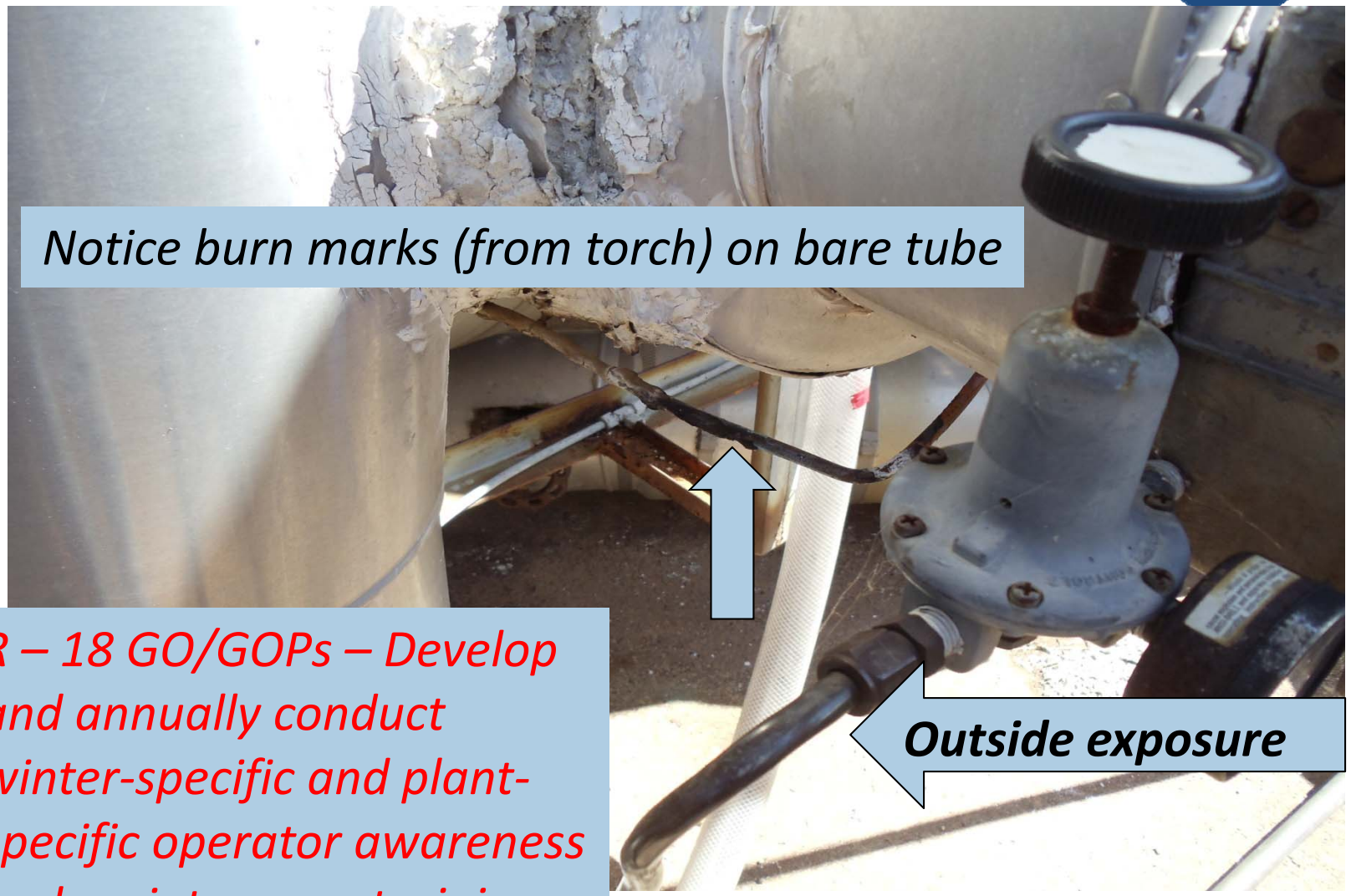
R 14 - GO/GOPs – Ensure that adequate maintenance and inspection of freeze protection elements is conducted on a timely and repetitive basis.

Inadequate Insulation



R-16 GO/GOPs – inspect and maintain thermal insulation on all units.

Lack of Insulation



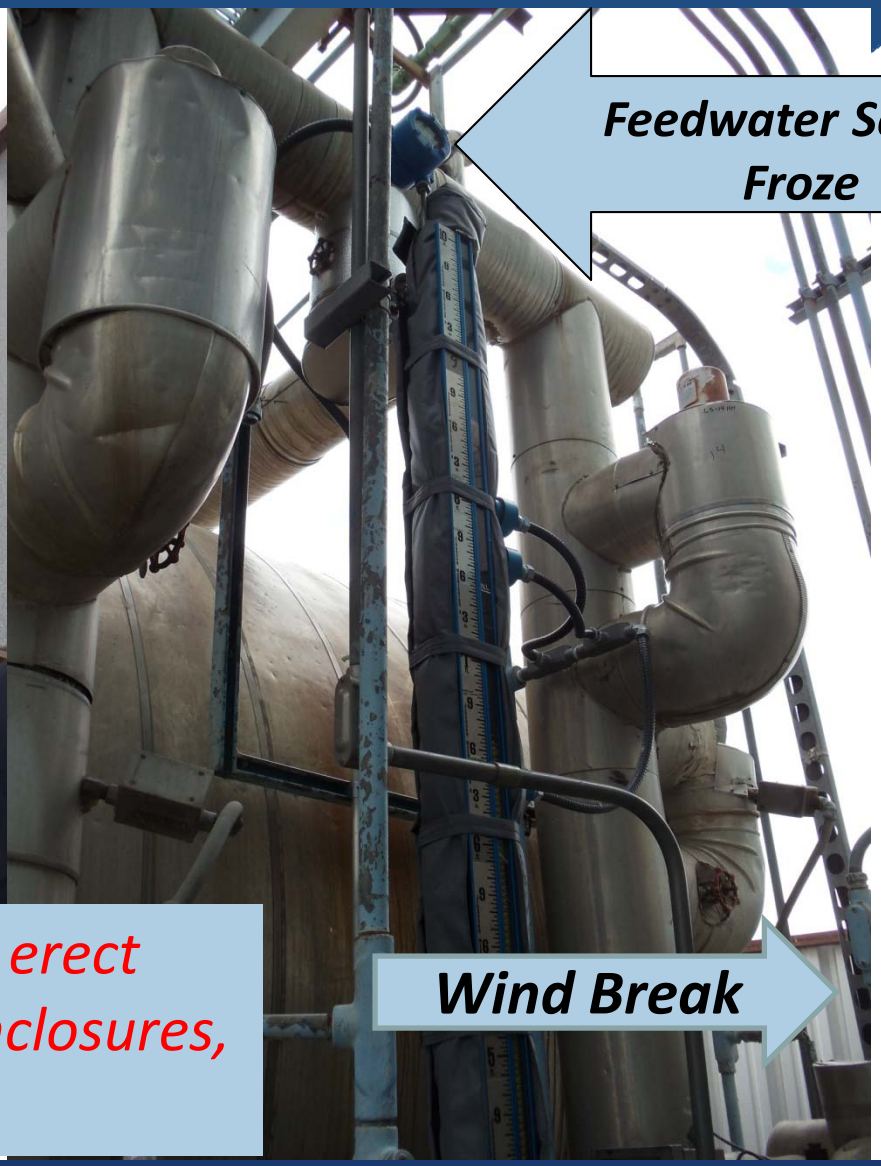
R – 18 GO/GOPs – Develop and annually conduct winter-specific and plant-specific operator awareness and maintenance training.

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Wind Break Design



Wind break was too Short

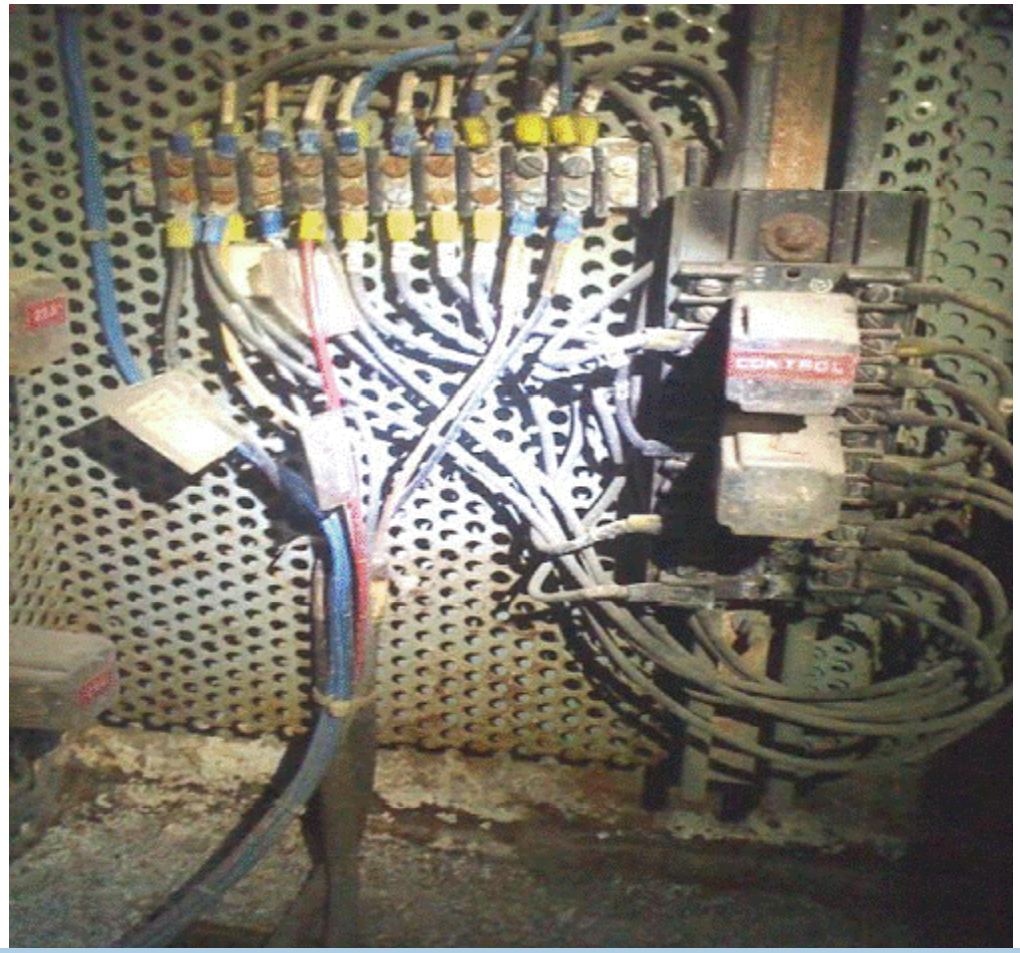


Feedwater Sensor Froze

Wind Break

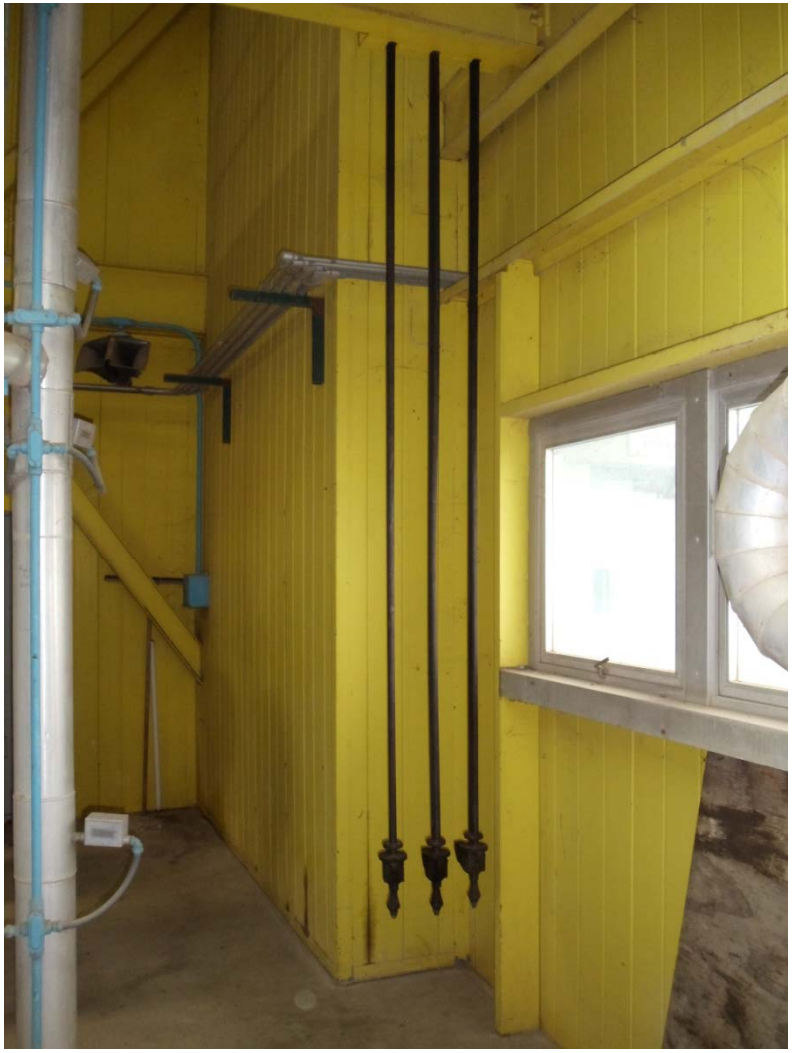
R – 17 GO/GOPs – Plan to erect adequate wind breaks and enclosures, where needed.

Corroded Freeze Protection Panel



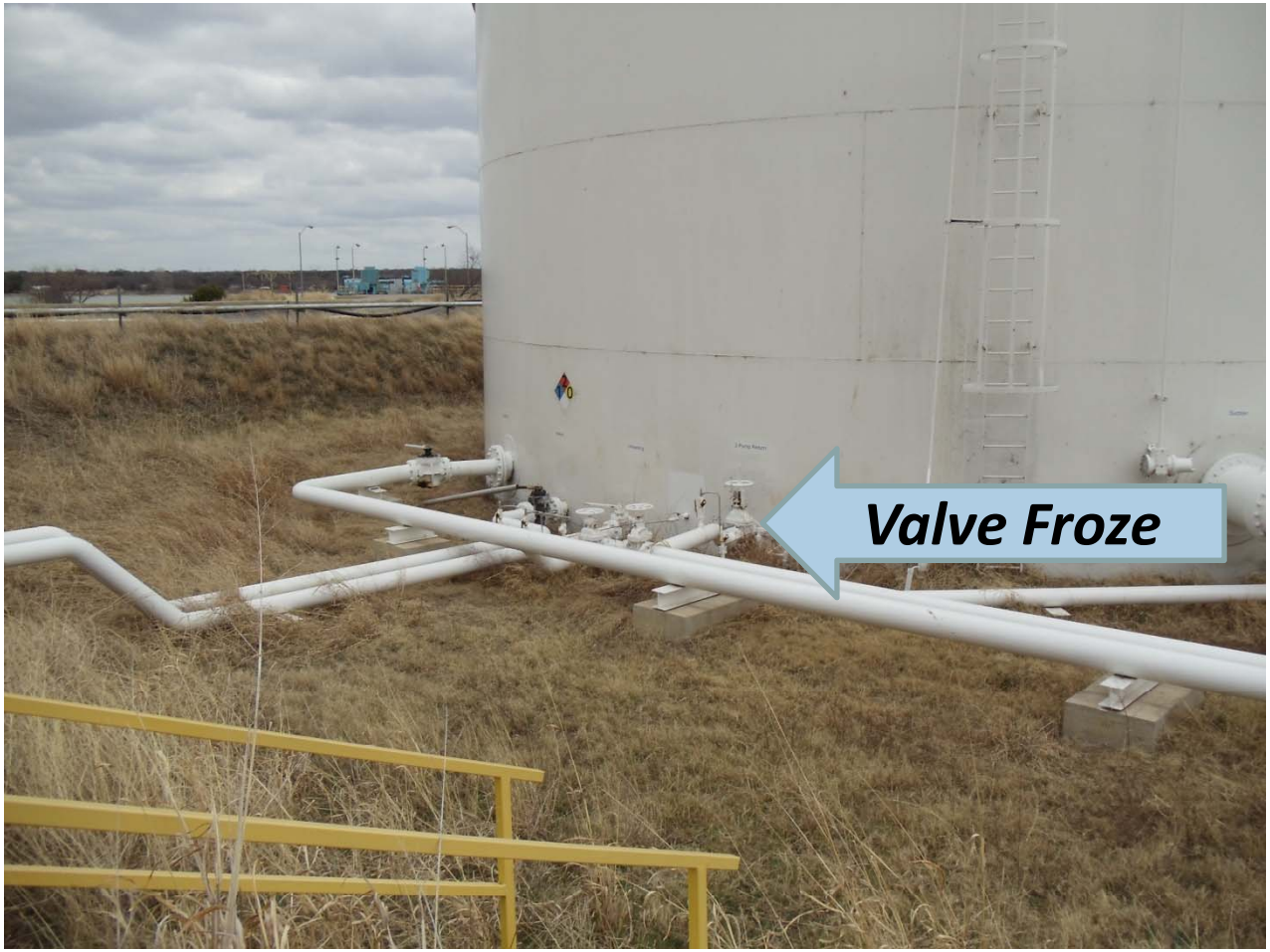
R – 15 GO/GOPs – Inspect and maintain heat tracing equipment on all generating units.

Oil Burning Wands



R – 6 TOs, BAs, and GO/GOPs – Verify that units that have fuel switching capabilities can periodically demonstrate those capabilities

Fuel Transfer Valves

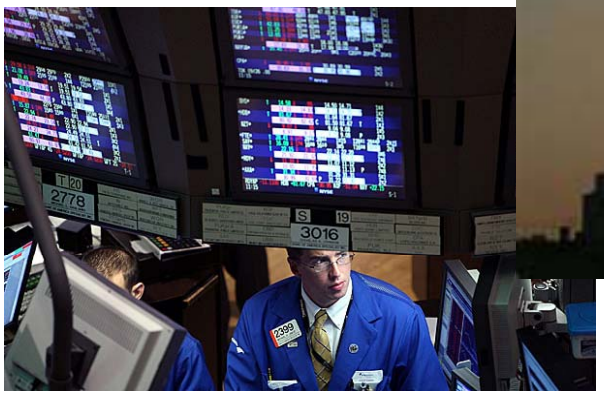


Lessons Learned

- NERC received a total of 55 lessons learned from entities impacted by the cold snap event.
- The lessons learned were reviewed by NERC, categorized and consolidated into 22 individual lessons that align with the recommendations outlined in the joint FERC/NERC report "Outages and Curtailments during the Southwest Cold Weather Event" published on August 15, 2011.
- On September 30, 2011 the first two cold snap lessons learned were posted to correspond with the fall maintenance program for winter weather preparation.
- Two additional lessons learned have been posted.

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Events Happen







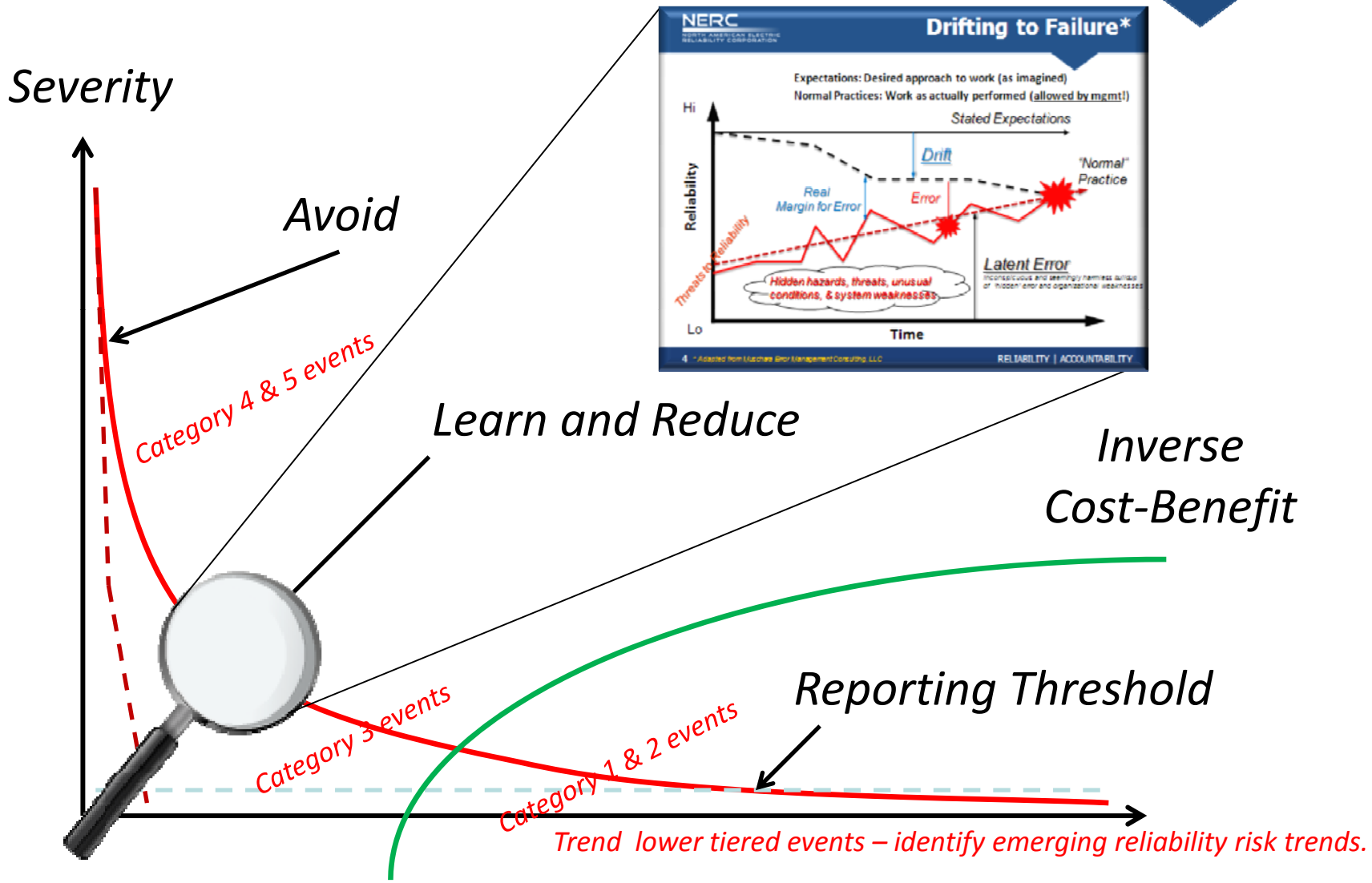




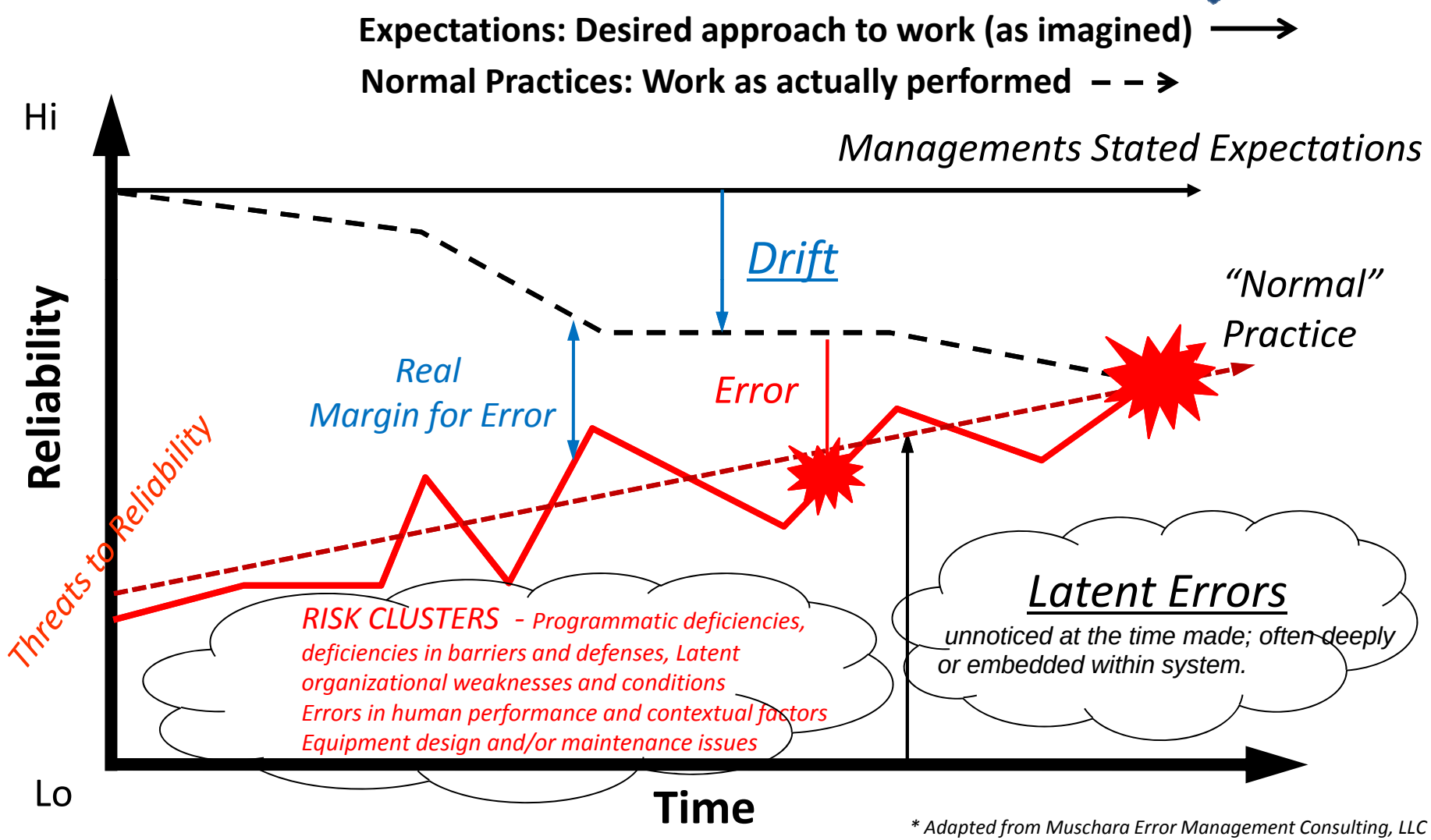




Reliability Risk Management Concepts

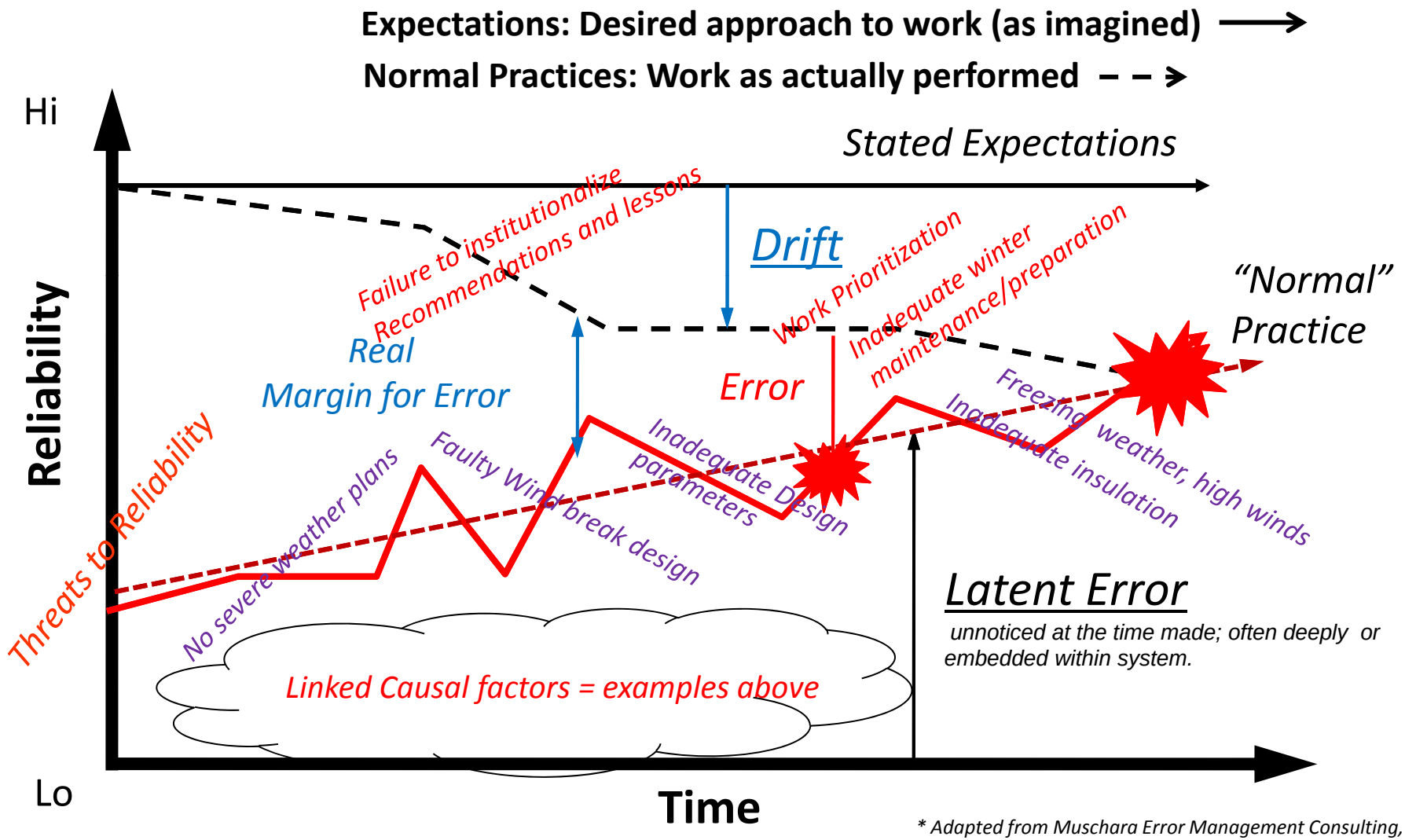


Drifting to Failure Concept*



* Adapted from Muschara Error Management Consulting, LLC

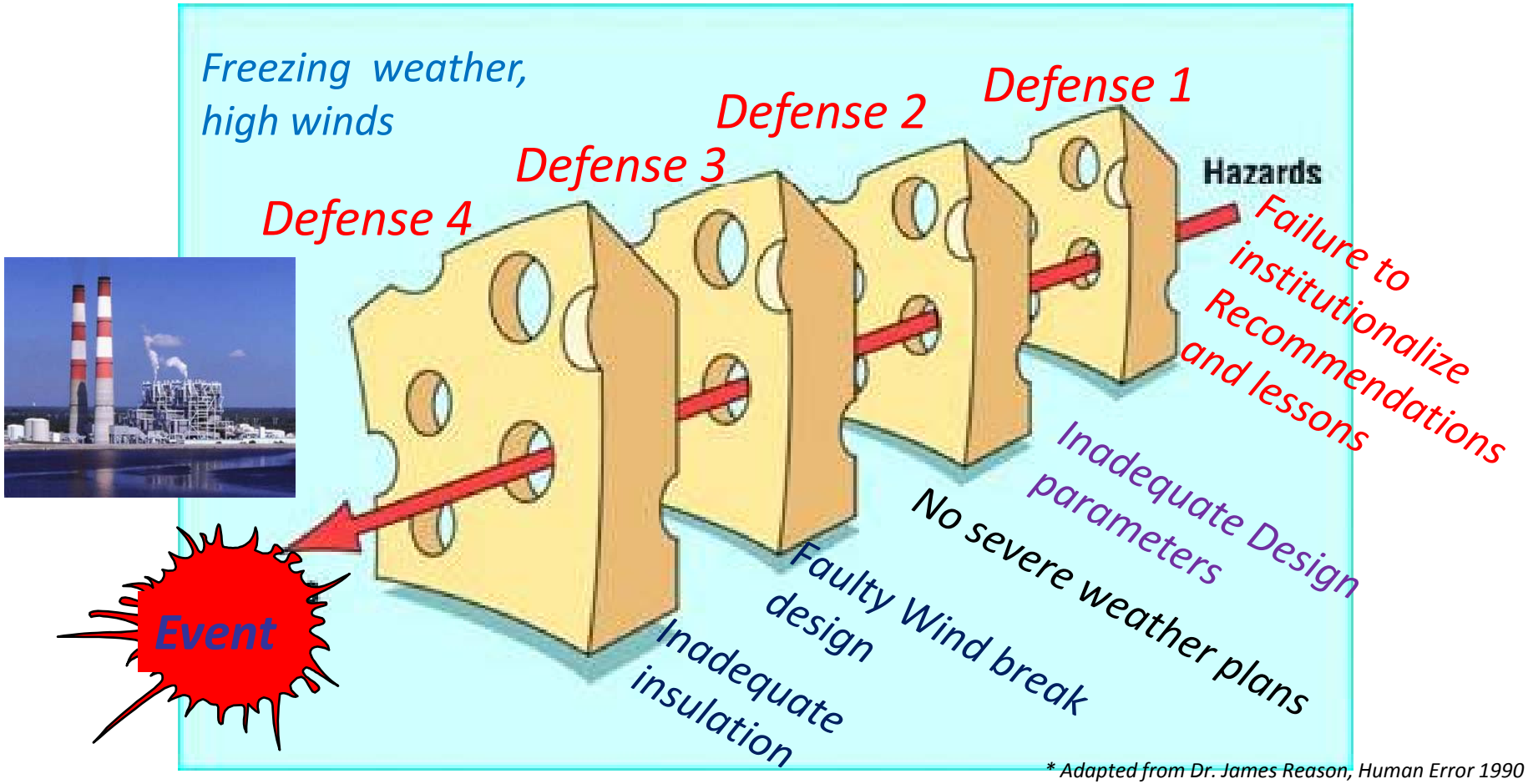
Cold Snap Event Drifting to Failure*



* Adapted from Muschara Error Management Consulting, LLC

Defense in Depth Concept*

When the <u>wrong set</u> of circumstances line up, major events occur…



** Adapted from Dr. James Reason, Human Error 1990*

Summary

- We do not want to lose our perspective of what happened during the winter of 2011
- Consider the three “P’s”
- Examine your safeguards



- We should consider the cost benefit as well as the risk to reliability and reputation:
  - Institutionalize recommendation and learning's
  - Show that we not only can identify problems but also put the necessary fixes in place.
- Have a passionate focus on reliability



Questions ?

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Agenda
ERO Auditor Overview, Industry Seminar

Thursday February 23, 2012 and Friday February 24, 2012
Western Electricity Coordinating Council (WECC)[1]
155 North 400 West, Suite 200
Salt Lake City, UT 84103-1114
(801) 582-0353

DRAFT

Purpose

Educate the industry regarding the ERO auditor process; specifically with regards to consistency, reliability, and transparency.

Objectives

1. Outline and explain audit authority.
2. Educate industry on how to evaluate and apply the processes, procedures, and tools that are available to conduct a fair, quality audit.

Agenda

Thursday, February 23, 2012

12:30pm - 1:00pm Sign-in and seating (Lunch Provided)

1:00pm - 1:05pm Administration – Jim Hughes (NERC)

- Welcome
- Logistics

1:05pm - 1:10pm Opening Remarks – Mike Moon (NERC)

- Seminar objectives
- Agenda and expected accomplishments

1:10pm - 2:00pm Session I – Comparative Approach to Auditing – Rick Dakin (CEO Coalfire)

Purpose: Educate the participants on auditing practices and illustrate controls that are being used in other industries.

Objective: This supports Objective 2.

[1] Room rate information found at:
http://www.wecc.biz/library/WECC Documents/Publications/WECC Salt Lake Office Visitor Information.pdf

Note taker: Bill Graham (NERC)

2:00pm – 3:00pm Session II – Audit Team Dynamics – Dr. James Merlo (NERC)

Purpose: Illustrate attributes of a successful audit team.

Objective: This supports Objective 2.

Note taker: Bill Graham (NERC)

3:00pm - 3:15pm Break

3:15pm – 4:00pm Session III – Compliance Application Notices (CANs) – Val Agnew (NERC)

- CAN updates
- CAN development and review processes
- Educate industry on how to evaluate and apply newly issued CANs

Purpose: Instruct industry on details of specific CANs and how they fit into the auditing process.

Objective: This supports Objective 2.

Note taker: Bill Graham (NERC)

4:00pm – 4:45pm Session IV – Reliability Standards Changes – Andy Rodriquez (NERC)

- 2012 Reliability Standards Changes and Their Affect on Auditing
  - BAL-002-1-0 Disturbance Control Performance
  - PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations
  - PER-003-01 Operating Personnel Credentials
- 2013 Reliability Standards Changes and Their Affect on Auditing
  - FAC-008-3 Facility Ratings
  - FAC-013-2 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
  - EOP-001-2 Emergency Operations Planning
  - EOP-005-2 System Restoration from Blackstart Resources
  - EOP-006-2 System Restoration Coordination
  - EOP-008-1 Loss of Control Center Functionality

Purpose: Educate auditors on the NERC Standards revisions that are becoming effective in 2012 and 2013.

Objective: This supports Objectives 1 and 2.

Note taker: Bill Graham (NERC)

4:45pm – 5:00pm Wrap-up of Day One – Jim Hughes (NERC)

Friday, February 24, 2012

7:30am - 8:00am Seating (Continental Breakfast Provided)

8:00am - 8:05am Opening Remarks – Jim Hughes (NERC)

- Welcome
- Agenda for the Day and Expected Accomplishments

8:05am - 8:45am Session V – Introduction to Auditing – Jason Patterson (NERC)

- FERC, NERC, Regional Entities and their relationships
- NERC compliance program
- Auditing practices
- Timeline of an audit

Purpose: Provide an overview of the ERO auditing process and application of auditing practices.

Objective: This supports Objectives 1 and 2.

Note taker: Bill Graham (NERC)

8:45am – 9:30am Session VI – Elements of a Successful Audit – Craig Struck (NERC)

- Auditor Tools
- Standards Suggestion Form
- Avoiding conflict of interest
- Confidentiality obligations
- Handling confidential information
- Data requests
- Planning an audit
- Conducting an audit

Purpose: Educate the industry on how to evaluate and apply the auditing process. Identify tools used by auditors.

Objective: This supports Objectives 1 and 2.

Note taker: Bill Graham (NERC)

9:30am – 9:45am Break

9:45am – 10:30am Session VII – Interviewing Skills – Stephanie Wood (NERC)

- Overview of interviewing; what, why, and who
- Planning the interview
- Conducting an interview
- Interviewing techniques

Purpose: Discuss and then apply techniques and tools used during interviews.

Objective: This supports Objective 2.

Note taker: Bill Graham (NERC)

10:30am – 11:15am Session VIII – Registration and Certification Issues that may Impact Audit Planning – Jack Wiseman (NERC)

- Joint Registration Organization (JRO) and Coordinated Functional Registration (CFR)
- Generator Operators (GO) registering as Transmission Operators (TO)
- Compliance Analysis Report (CAR) – Registration[2] Certification[3]

Purpose: Educate auditors on JRO and CFR processes, the GO/TO project, and on CARs. And, instruct on the possible impact these items have on auditing.

Objective: This supports Objective 2.

Note taker: Bill Graham (NERC)

11:15am – 11:30am Closing Remarks and Final Questions – Jim Hughes (NERC)

- Open forum
- Adjourn

[2] http://www.nerc.com/files/NERC_Compliance_Registry_and_Registration_Appeals.pdf
[3] http://www.nerc.com/files/Organization%20Certifications1.pdf

Performance Analysis Subcommittee Meeting Notes
NERC Offices - Atlanta, GA
January 31 – February 1, 2012

The Performance Analysis Subcommittee (PAS) spent most of its time discussing how it will develop the 2012 report on the "State of the Reliability" of the electric power system of North America. PAS targets a draft report to be completed by September.

The 2011 data from TADS, GADS, EA and post seasonal assessments would be analyzed and presented in this report. The structure/outline of this report could be based on:

- Six characteristics of Adequate Level of Reliability (ALR) performance metrics,
  - Boundary
  - Contingencies
  - Integrity
  - Protection
  - Restoration
  - Adequacy
- Risk indicators or indexes
  - Standard Driven Index (based proposed on attached 26 high risk standard requirements) – expected to bring this to OC and PC in June
  - Event Driven Index (based on load loss, transmission outages, and generation outages) – target OC and PC approval in March
  - Condition Driven Index (based on attached 18 ALR metrics) – expected bring this index to OC and PC in Fall.

PAS reviewed the attached WECC Reliability Vulnerabilities Initiative, which seeks to identify trends, risks and vulnerabilities through analysis of data collected from standard compliance, system outage, performance data, and reliability assessments. This initiative is intended to supplement and add value to work being done by NERC PAS.

PAS also reviewed the following ALR metrics:

ALR6-15 and ALR6-16– Element availability and unavailability – suggested data for these two be combined into a stack bar chart.

ALR6-2 and ALR6-3 – add duration, count will stay with ALR6-2 and ALR6-3 / EEA2s are non-firm load and voltage reduction. EEA3s are firm load (from RC Information System). It was questionable if EEA2 data is complete because reporting is by request. EEA3 reporting is required. PAS will go to ORS on how the EEA2 is reported.

ALR6-4 – This metric is tabled until further information is available.

ALR5-1 – Average EEA duration

ALR5-5 – Mean restoration time, measure average duration of restoration time after an OE-417 reportable event. It's a measure of the ability of the system to be restored promptly. This metric will be sent out to the group for comments.

Reliability Coordinating Committee
March 1, 2012
Draft Preliminary Agenda

Consolidated Edison Company of New York, Inc.
Four Irving Place
New York, New York 10003
19th Floor Auditorium

(212) 780-6444

March 1, 2012
10:00 a.m. to 3:00 p.m.
Dial-In Number: (719) 785-1714
Code: 8093

1.0 Introductions/Quorum/Antitrust Compliance Guidelines

2.0 President & CEO Report
- 2.1 February 1, 2012 NPCC Board Meeting
- 2.2 Development of NPCC 2013 Business Plan & Budget
- 2.3 NERC Board of Trustees/Member Representatives Committee

3.0 RCC Chair Report
- 3.1 Agenda
- 3.2 NPCC website password change
- 3.3 RCC Scope
- 3.4 Approved 2012-2013 RCC Work Plan
- 3.5

4.0 Consent Agenda (vote to approve in a single motion) [Action Required]
- 4.1 November 29, 2011 Draft-For-Approval Meeting Minutes
- 4.2 Roster Changes
- 4.3 Task Force Roster Changes
- 4.4 2011 New York Intermediate Transmission Review
- 4.5
- 4.6

5.0 Items for Approval [Action Required]
- 5.1 Modification of the Bruce Type I SPS
- 5.2 2011 NPCC Long Range Adequacy Overview
- 5.3

6.0 NPCC 2012 Summer Reliability Assessment(s)
- 6.1 Preliminary results

NPCC, Inc.

Reliability Coordinating Committee
March 1, 2012
Draft Preliminary Agenda

6.2 Approval Schedule
6.3 Media Event

7.0 Status Reports

Standards

7.1 NPCC Regional Standards Committee Report
7.2 Reliability Directory Status

Compliance

7.3 NPCC Compliance Committee Report

Task Force Activities

7.4 Blackout Study Recommendations
7.5 TFCO Directory No. 5 Follow-up
7.6 TFSP SP-7 Working Group
7.7 TFCP Phase 2 – Directory No. 1
7.8 SS-38 - Load Modeling Study
7.9 TFSS - SPS List, Major Projects List, BPS List, and DCT Exclusions List
7.10 2012-2013 Work Plan Progress
- 7.10.1 Task Force on Coordination of Operation
- 7.10.2 Task Force on Coordination of Planning
- 7.10.3 Task Force on Infrastructure Security and Technology
- 7.10.4 Task Force on System Protection
- 7.10.5 Task Force on System Studies

7.11 NPCC Reliability Assessment Program (NRAP) Summary Report

8.0 NERC Agenda Items

8.1 Operating Committee
8.2 Planning Committee
8.3 Critical Infrastructure Protection Committee

9.0 Informational Items

9.1 Homer City-Watercure & Homer City-Stolle Road 345 kV Line Protection
9.2 Summary of NERC/FERC Data Requests
9.3 NERC Items
- 9.3.1 Model Validation Task Force
- 9.3.2 Events Analysis Program
- 9.3.3 Geomagnetic Disturbance Task Force Report

9.4 Definition of Bulk Electric System Standards Drafting Team (Project 2010-17)
9.5 New Pinard Cross tripping Type III SPS
9.6 NPCC Operational Highlights
9.7 Eastern Interconnection Planning Collaborative

NPCC, Inc.

Reliability Coordinating Committee
March 1, 2012
Draft Preliminary Agenda

9.8 Eastern Interconnection Reliability Assessment Group
9.9
9.10

10.0 Other Matters

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Background Information

For Quality Reviews

February 7, 2012

RELIABILITY | ACCOUNTABILITY






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Introduction

Purpose

Each reliability standard must have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system. The purpose statement should identify the reliability-related benefit of the standard and should be tied to at least one of the reliability principles.

The set of requirements in the standard should collectively support the purpose statement.

Applicability Section of the Standard

The applicability section of the standard should identify all of the functional entities assigned responsibility for one or more requirements in the standard. While standard drafting teams should use the same terminology for identifying responsible entities as used in the compliance registry, the compliance program may authorize deviations where needed for reliability.

The applicability section should also include any limitations on the applicability of the standard based on electric facility characteristics, such as a requirement that applies only to the subset of distribution providers that own or operate underfrequency load shedding systems.

The applicability section should also identify situations where one or more requirements apply to just a subset of the bulk power system such as requirements that apply only to Transmission Lines rated at 200kV or higher.

This section may also identify specific conditions under which one or more requirements may or may not apply.

Requirements

Each reliability standard must include one or more requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest.

Each requirement must establish an objective that is the best approach for bulk power system reliability, considering the costs and benefits of implementing the proposal. Each requirement must be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement. Requirements should have the following characteristics:

- Each requirement must identify what functional entity shall do what, under what special conditions (if any), for what reliability benefit.
- Each requirement should be aimed at achieving one objective and written in the 'active' voice.
- If specific results can be practically measured quantitatively, metrics should be provided within the requirement to indicate satisfactory performance.
- To the maximum extent possible the requirement must be designed to apply throughout the interconnected North American Bulk-Power System.

Reliability standards should not contain:

- Requirements that prescribe commercial business practices which do not contribute directly to reliability.
- Reliability standards should not contain requirements that duplicate or conflict with one another.

Requirements referencing an attachment:

- If a requirement references an attachment (such as a requirement that says, "in accordance with attachment x") then that attachment is an extension of the requirement, and should be reviewed as such.

Measures and Evidence Retention

Measures

Each requirement must have one or more associated measures used to objectively evaluate compliance with the requirement. A single measure may be used to address more than one requirement. Each measure must identify the functional entity with the performance being measured – the same functional entity that is responsible for the associated requirement. Each measure must be tangible, practical, and as objective as is practical. Measures should support requirements by identifying what evidence or types of evidence could be used to show that an entity is compliant with the requirement. For some requirements, only one type of evidence is acceptable – but for many requirements, a range of evidence could be acceptable. The following is a synopsis of the guidelines provided to drafting teams:

- If the requirement is to have a document such as an agreement, methodology, or procedure, then the measure should require the responsible entity to provide that document – and if the requirement has timing-related aspects such "current" or "updated" then the evidence must include references to dates.
- If the requirement is to verify something, then the measure should include the criteria for verification (if applicable) as well as the evidence to support that the verification was conducted – and if the verification is required to be executed on some periodic basis, then the evidence must include references to dates.
- If the requirements is to "do" something such as perform maintenance, communicate information, provide data – then the measure must include evidence that the action was performed – and if the action is required under specified conditions or with some specified frequency, then evidence of the conditions under which the action was performed as well as a reference to the time when the action was performed should be included in the measure.
- Attestations are acceptable. An attestation has to be made by an individual, not just on behalf of an entity. This put an individual's character on the line, and tends to make people be more truthful. If it turns out to be false, that is considered in the determination of the penalty for the entity.

Evidence Retention

On January 1, 2011 the Rules of Procedure Appendix 4c – Section 3.1.4.2 that became effective Jan 1, 2011 included the following:

> 3.1.4.2 Period Covered
>
> The Registered Entity's data and information should show compliance with the Reliability Standards that are the subject of the Compliance Audit for the period beginning with the day after the prior audit by the Compliance Enforcement Authority ended (or the later of June 18, 2007 or the Registered Entity's date of registration if the Registered Entity has not previously been subject to a Compliance Audit), and ending with the End Date for the Compliance Audit. However, if another Compliance Monitoring and Enforcement process has been conducted with respect to the Registered Entity subsequent to the date that would otherwise be the start of the period, the period covered by the Compliance Audit may, in the Regional Entity's discretion, begin with the completion of that Compliance Monitoring and Enforcement process for those Reliability Standards requirements that were the subject of the Compliance Monitoring and Enforcement process. The End Date will be stated in the Compliance Enforcement Authority's notification of the Compliance Audit issued to the Registered Entity pursuant to Section 3.1.1. The Registered Entity will be expected to demonstrate compliance for the entire period described above. However, if a Reliability Standard specifies a document retention period that does not cover the entire period described above, the Registered Entity will not be found in noncompliance solely on the basis of the lack of specific information that has rightfully not been retained based on the retention period specified in the Reliability Standard. However, in such cases, the Compliance Enforcement Authority will require the Registered Entity to demonstrate compliance through other means.

To ensure that responsible entities understand the above, drafting teams have been advised to include the following paragraph as the first paragraph in the Evidence Retention section of the standard.

> 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.

There are two types of evidence that must be kept – evidence used by entities to show that they are compliant with the requirements and evidence retained by the CEA to verify that it has assessed compliance. The measures should serve as a guide in identifying which responsible entity must keep what evidence for how long.

For the "Data/Evidence Retention" section of the standard, the following default language is recommended for identification of retention periods – with variations to the sentence structure as needed:

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 [responsible entity] shall retain evidence of Requirement 1, Measure 1 for [Insert Time Period].

If a [responsible entity] is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

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

The following tables were extracted from the latest approved version of "Drafting Team Guidelines"

http://www.nerc.com/files/NERC_Drafting_Team_Guidelines_Endorsed_by_SC_April2009.pdf

Agreements, Training, Records, Procedures, Processes, Plans, Methodologies, Models		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Have an agreement	Dated document with confirmation of agreement Dated electronic communications with confirmation of agreement	Current, in force agreement and agreements in force since last compliance audit period.
Document authority	Dated job description that includes statement of authority with respect to other operating entities Dated letter declaring authority signed by an authorized and appropriate corporate officer Dated department notice signed on corporate letterhead Dated Agreement with authority documented	Current, in force document and any documents in force since last compliance audit period.
Have a set of requirements, process, plan, procedure, methodology, or other document– no requirement to update	Dated, current, in force document with specified elements	Current, in force document and any documents in force since last compliance audit period.
Have a set of requirements, process, plan, procedure, methodology, or other document–requirement to update	Dated, current, in force document with specified elements and evidence of last issue	Current and previous 3 years' versions Current, in force document plus the 'date change page' from each version issued since the last audit or the current and previous version All versions from prior 3 years

Agreements, Training, Records, Procedures, Processes, Plans, Methodologies, Models		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Have a specific record with no mention of update	Dated, specified record in electronic or hard copy format	Current, in-force and at least one previous period
Have specific operational plan (real-time, next day, seasonal) with specified elements	Dated, actual plan with specified elements	Rolling 6 months or previous document, whichever is longer.
Have a model	Model	Latest version and evidence of the previous version.

Verifications		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Verify personnel qualifications	Dated certification records Training records showing successful completion with description of training activity and employee name, date Supervisor check sheets showing employee name, date performance noted Records showing mastery or completion with employee name, date	Latest verification of each qualification records for rolling 6 months
Verify facility meets specified criteria	Dated demonstration that facility meets criteria Dated Equipment specification showing facility meets criteria Dated installation documentation showing	Current and previous set of evidence if updated since previous compliance audit

Verifications		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
	that facility meets criteria Dated test results to show that facility meets criteria Dated computer output to show that facility meets criteria	
Verify accuracy of data	Verification process and results with date verified	Latest and prior verification
Verify accuracy of data – requirement to update on a specified periodicity	Verification process and results with date verified	Latest and prior
Verify specific training occurred– no minimum hour requirement	Actual training program materials or description with dated completion records for employees	3 calendar years
Verify specific training occurred– minimum hour requirement	Actual training program materials or description with dated completion records for employees and # of course hours	3 calendar years
Verify staff has proper certification	Staffing plan Certification numbers for personnel in staffing plan	Current plus previous year

Perform, Implement, Execute, Develop, Maintain		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Perform a mathematical calculation via	Dated data to support the calculation	Unless otherwise specified in the standard:

Perform, Implement, Execute, Develop, Maintain		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
computer and report results on a periodic basis	retained in an electronic format Dated hard copy of output of mathematical calculation plus documented formula and input Dated copies of periodic reports	For calculations done on a continuous basis (e.g. hourly, daily, and up to weekly) – most recent 3 calendar months For calculations done on a monthly basis – 1 calendar year For calculations done on a periodicity longer than monthly – 3 calendar years
Implement follow up plan	Follow up plan that includes timetable for implementation with check sheet to show date each milestone achieved	12 months after implementation plan completed
Perform maintenance in accordance with schedule	Schedule plus maintenance records showing date and what was done	3 calendar years
Perform testing or simulation in accordance with schedule	Schedule plus test records (or simulation records) showing date of test, type of test, what was tested, test procedure, test results	3 calendar years
Conduct an assessment (impact of connecting new facilities; effectiveness of SPS; SPS operations; long-range plan)	Results of assessment with assumptions, contingencies, models used	6 calendar years
Perform an analysis of an event with a follow up plan (mitigation plan, corrective action plan)	Analysis report and follow up plan that includes time table for implementation	12 months after implementation plan completed
Have and follow a maintenance, testing, or other program (vegetation management)	Paper or electronic copy of program with schedule and records showing what was done to implement the program with dates and activities accomplished	3 calendar years

Perform, Implement, Execute, Develop, Maintain		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Develop ratings or limits according to methodology	Methodology accompanied by ratings or limits Demonstrate limits developed according to methodology	12 months or previous limits and methodology whichever is longer.
Maintain specified data	Database with specified data List in hard copy or electronic format with specified data	Latest version and evidence of a previous version.

Operate, Request, Communicate		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Operate within defined parameters	Dated parameters and report of any event with operation outside defined parameters including date, time, duration, details of how far outside parameters	Exception reports – 3 calendar years *(Under 'Additional Compliance Information' - Submit report of exceedances (use proper name of report) to CEA within 30 days of the initiation of the event*
Respond to reliability-related concerns	Paper or electronic notice of response showing date, name and title of responder and any action to be taken in response to reliability-related concern with	Notices and responses – 3 calendar years *(Under 'Additional Compliance Information' - Copy of concern and within 30 days of receipt/response)*
Request data or information	Dated paper or electronic notice used to request data showing data, recipient, and	Latest issued

Operate, Request, Communicate		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
	data or information requested	
Communicate operating information (requirements to notify, direct, inform, or communicate operating information to others who need the information to take action)	Dated operator Logs	Most recent 12 months
	Voice recordings or transcripts of voice recordings	Most recent 3 months

Report, Provide Data or Information		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
Distribute or make a set of limits, procedure, process, plan, report or other prepared document available to others	Email notice with updated web page Postal receipt showing recipient, date, contents Demonstration of public posting (if not required to distribute to specific people)	1 calendar year for items that are updated at least monthly 3 calendar years for items that are updated less than once a month
Post information on web and ensure entities know of updated information	Link to web page and either a copy of the electronic notice sent to advise recipients of the posting or a postal receipt showing recipient, date and contents	90 calendar days
Post updated information on web	Link to web page	90 calendar days
Submit operating data or information as requested and according to schedule	Request for data with schedule accompanied by copy of transmittal notice including identification of data submitted, date	90 calendar days

Report, Provide Data or Information		
Sample Requirement	**Type of Evidence Specified in Associated Measure**	**Recommended Evidence Retention Period**
	submitted	
Submit planning data or information as requested and according to schedule	Request for data with schedule accompanied by copy of transmittal notice including identification of data submitted, date submitted	1 calendar year or the last planning cycle whichever is longer.
Submit data related to a disturbance or event	Request for data with transmittal notice including identification of data submitted, date submitted	3 calendar years or for the duration of any regional investigation, whichever is longer. (This should be a long time as there may be a need to investigate further if a similar event occurs.)

Compliance Elements Used to Administer Compliance

Compliance Enforcement Authority

For most standards, the compliance enforcement authority will be the 'Regional Entity' and this is what should be entered. If the Regional Entity is the responsible entity or the responsible entity works for the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity) to be responsible for compliance enforcement.

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority 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.

For NERC, a third-party monitor without vested interest in the outcome for NERC shall serve as the Compliance Enforcement Authority.

Compliance Monitoring and Assessment Processes

This section identifies the processes that may be used by the CEA to monitor compliance with the requirements in the standard. There are eight processes defined in the Uniform Compliance Monitoring and Enforcement Program (CMEP) of the North American Electric Reliability Corporation, and for most standards, the first six of the eight processes listed below are applicable. The last two processes (Periodic Data Submittals and Exception Reporting) are only applicable in certain standards. With the exceptions noted for periodic data submittals and exception reporting, drafting teams should not add descriptive language to identify "how" a process will be implemented as the CMEP includes details on the implementation of each of these processes.

1. Compliance Audit
2. Self-Certification
3. Spot Checking
4. Compliance Investigation
5. Self-Reporting
6. Complaint
7. Periodic Data Submittals – If periodic data submittal is listed, the submittal interval must be specified. The details should be included in the "Additional Compliance Information" section of the standard.
8. Exception Reporting – If exception reporting is listed, the conditions for the report must be specified. The details should be included in the "Additional Compliance Information" section of the standard.

Compliance Elements Used to Assist in Assigning Penalties and Sanctions

Time horizons, Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are used as a factor in determining the size of a penalty or sanction for noncompliance with the requirement.

Time Horizons

Each requirement must have an associated Time Horizon to identify the time frame an entity would have to correct a violation of the requirement. The Time Horizons and the criteria for each include:

- Long-term Planning — a planning horizon of one year or longer.
- Operations Planning — operating and resource plans from day-ahead up to and including seasonal.
- Same-day Operations — routine actions required within the timeframe of a day, but not real-time.
- Real-time Operations — actions required within one hour or less to preserve the reliability of the bulk electric system.
- Operations Assessment — follow-up evaluations and reporting of real time operations.

Violation Risk Factors

Each requirement must have an associated violation risk factor (High, Medium or Lower). The risk factor assesses the impact to reliability of violating a specific requirement. The following criteria have been filed with FERC as part of the ERO's Sanctions Guidelines and must be used to determine a violation risk factor for each requirement:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the

preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

In addition, in its May 18, 2007 Order on Violation Risk Factors, FERC identified five "guidelines" it uses to determine whether to approve the Violation Risk Factors submitted for approval. Those factors are:

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

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. From footnote 15 of the May 18, 2007 Order, FERC's list of critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System includes:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

In addition, NERC established the following detailed guidelines for setting VSLs:

1. If the requirement is binary, or when any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement, then the single VSL must be "Severe". (This is not the same as saying that the requirement is really important and any noncompliance would have an adverse reliability impact – the impact to reliability should be addressed through the VRF, not the VSL.)

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
EOP-002 R3.	N/A	N/A	N/A	The Balancing Authority experienced an operating capacity or energy emergency and failed to communicate its current and future system conditions to its Reliability Coordinator and its neighboring Balancing

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Authorities.
EOP-005 R8.	N/A	N/A	N/A	The Transmission Operator resynchronized without approval of the Reliability Coordinator or not in accordance with the established procedures of the Reliability Coordinator following a Disturbance in which Blackstart Resources were required for restoring the shut down area of the BES to service.

2. If the requirement has a wide range of possible noncompliant performance the requirement should have multiple VSLs.

   There are many different ways of developing VSLs to categorize different degrees of noncompliant performance. The set of VSLs developed should collectively address all of the elements in the requirement. Thus, if a requirement includes both specific actions and a timeframe for completion of those actions, then the VSLs should address noncompliance with both the completeness of the actions and the timeliness of those actions. Not all VSLs need to address both components of the requirement, but collectively the set of VSLs must address all aspects of the requirement.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-009 R2.	The responsible entity that owns or operates a UFLS program (as required by its Regional Reliability	The responsible entity that owns or operates a UFLS program (as required by its Regional Reliability	The responsible entity that owns or operates a UFLS program (as required by its Regional Reliability	The responsible entity that owns or operates a UFLS program (as required by its Regional Reliability

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Organization) provided its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database but its annual update was late by 30 calendar days or less.	Organization) provided its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database but its annual update was late by more than 30 calendar days but less than or equal to 40 calendar days.	Organization) provided its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database but its annual update was late by more than 40 calendar days but less than or equal to 50 calendar days.	Organization) did not provided its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database, OR The responsible entity's annual update was late by more than 50 calendar days.

3. If the requirement has multiple parts that contribute unequally to the reliability-related intent of the requirement, each numbered part of the requirement should be identified separately in the VSLs.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
EOP-001 R7.	The responsible entity demonstrated that it coordinated its emergency plans with other Transmission Operators and Balancing Authorities as appropriate but the coordination specified in R7, Part 7.4 was applicable and was not	The responsible entity demonstrated that it coordinated its emergency plans with other Transmission Operators and Balancing Authorities as appropriate but the coordination specified in R7, Part 7.3 was applicable and was not	The responsible entity demonstrated that it coordinated its emergency plans with other Transmission Operators and Balancing Authorities as appropriate but the coordination specified in either R7, Part 7.1 or in R7, Part 7.2 was	The responsible entity demonstrated that it coordinated its emergency plans with other Transmission Operators and Balancing Authorities as appropriate but the coordination specified in two (2) or more of the four (4) Parts of

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
	included.	included.	applicable and was not included.	Requirement R7 were applicable and were not included.

4. If the requirement has multiple parts that contribute equally to the reliability-related intent of the requirement, the VSLs should be set based on the number of parts that are noncompliant or a percentage of noncompliant performance without regard to which part is "missing" or noncompliant.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-009 R1.	The responsible entity that owns or operates a UFLS program failed to include **one** of the elements listed in PRC-009-0 Requirement R1, Parts 1.1 through 1.4 in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.	The responsible entity that owns or operates a UFLS program failed to include **two** of the elements listed in PRC-009-0 Requirement R1, Parts 1.1 through 1.4 in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.	The responsible entity that owns or operates a UFLS program failed to include **three** of the elements listed in PRC-009-0 Requirement R1, Parts 1.1 through 1.4 in the analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.	The responsible entity that owns or operates a UFLS program failed to conduct an analysis of the performance of UFLS equipment and Program effectiveness, as described in PRC-009-0 Requirement R1, following system events resulting in system frequency excursions below the initializing set points of the UFLS program.

5. If noncompliance is measured as a percentage, the VSLs should be incremented by 5% with 5% or less as a Lower VSL; more than 5% up to and including 10% as Moderate; more than 10% up to and including 15% as High; and more than 15% noncompliant as a Severe VSL.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-016 R2.	For each Misoperation, the responsible entity that owns an SPS failed to take 5% or less of the corrective actions designed to avoid future SPS Misoperations.	For each Misoperation, the responsible entity that owns an SPS failed to take more than 5% up to (and including) 10% of the corrective actions designed to avoid future SPS Misoperations.	For each Misoperation, the responsible entity that owns an SPS failed to take more than 10% up to (and including) 15% of the corrective actions designed to avoid future SPS Misoperations.	For each Misoperation, the responsible entity that owns an SPS failed to take more than 15% of the corrective actions designed to avoid future SPS Misoperations.

6. If the requirement has a timing element associated with delivering something within a specified number of days and noncompliance is addressed in multiple VSLs, the increments in the number of "days late" should be set at 10 days.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
PRC-016 R3.	The responsible entity provided documentation of its SPS Misoperation analyses and the corrective action plans more than 90 calendar days but less than or equal to 120 calendar days following a request from its Regional Reliability Organization or NERC.	The responsible entity provided documentation of its SPS Misoperation analyses and the corrective action plans more than 120 calendar days but less than or equal to 130 calendar days following a request from its Regional Reliability Organization or NERC.	The responsible entity provided documentation of its SPS Misoperation analyses and the corrective action plans more than 130 calendar days but less than or equal to 140 calendar days following a request from its Regional Reliability Organization or NERC.	The responsible entity provided documentation of its SPS Misoperation analyses and the corrective action plans more than 140 calendar days following a request from its Regional Reliability Organization or NERC.

7. The VSLs should be size-neutral so that they treat noncompliance with large and small entities similarly.

When developing VSLs based on percentages or numbers, ensure that the developed VSLs are "size neutral." In some instances, applying a percentage to an entity with a small size may result in grading a violation higher or lower than might be intended. Similarly, applying a fixed number to an entity with a large size may result in a determination of violation that is higher or lower than might have been intended. In such cases, establish VSLs that categorize noncompliant performance by referencing either a percentage of noncompliant performance or a fixed number of noncompliant items.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
MOD-001 R7	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for 5% or less of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater).	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% but less than (or equal to) 10% of all ATC Paths or Flowgates but not more than 2 ATC Paths or Flowgates (whichever is greater).	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10% but less than (ore equal to) 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater).	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater).

In its June 19, 2008 *Order on Violation Severity Levels*, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

> **Guideline 1:** Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance (Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.)
>
> **Guideline 2:** Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties (A violation of a "binary" type requirement must be a "Severe" VSL. Avoid using ambiguous terms such as "minor" and "significant" to describe noncompliant performance.)
>
> **Guideline 3:** Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement (VSLs should not expand on what is required in the requirement.)
>
> **Guideline 4:** Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations (. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.)

In its March 18, 2010 Order Addressing VSL Assignments in CIP Standards, FERC offered the following additional guidance relative to VSLs for CIP requirements:

> Specifically, we have developed the following two additional guidelines for analyzing the validity of Violation Severity Levels that pertain to cyber security:
>
> (1) Requirements where a single lapse in protection can compromise computer network security, i.e., the "weakest link" characteristic, should apply binary rather than gradated Violation Severity Levels; 11 and
>
> (2) Violation Severity Levels for cyber security Requirements containing interdependent tasks of documentation and implementation should account for their interdependence.

General Attributes of the Standard in Total

Scope — Each reliability standard must be within the scope of the associated Standard Authorization Request (SAR). The requirements can address a scope that is smaller than the scope identified in the SAR, but the requirements may not go beyond the work specified in the SAR. If a drafting team wants to develop requirements that go beyond the scope of the SAR, the team must request authorization from the Standards Committee to propose a "supplemental SAR" for stakeholder comment. If a reviewer does not have the technical knowledge to make a judgment, the review may decline from answering this question.

Completeness — Each reliability standard must be complete and self-contained. The standards can't depend on external information to determine the required level of performance.

Practicality — Each reliability standard should establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter. Consideration must be made when assessing the practicality of implementation for the size of the responsible entities (investor owned utilities verses local municipalities and cooperatives).

Consistent Terminology — Each reliability standard, to the extent possible, must use a set of standard terms and definitions (Glossary of Terms Used in NERC Reliability Standards) that are developed and approved through the NERC Reliability Standards Development Process.

Regulatory Directives & Stakeholder Comments — Each drafting team must identify how it addressed each of the issues associated with the standard that were previously identified by stakeholders and regulatory authorities. Drafting Teams may identify a method that is "equally effective and efficient" to achieve the reliability intent of a directive, but if the drafting team does so; it should ask stakeholders (in the comment form) for feedback. For each regulatory directive that is phrased, ". . . direct ... to consider the comments from . . ." the team should provide (in the comment form) its analysis of the proposal, and a question asking stakeholders if they agree with the team's recommendation.

Variances — Each proposed variance must be accompanied by a justification for that variance that explains why the region wants its own criteria to apply rather than the continent-wide criteria. A variance for a requirement must include the requirement, associated measure, evidence retention, VRF, Time Horizon, and VSL. If the drafting team submits a variance it should identify whether the team supports the variance and should identify the impact to the continent-wide standard if the standard were revised so that the variance were not needed.

Compatibility with Existing Standards — Each standard should coordinate with existing enforceable standards without duplicating or conflicting with any already approved requirements.

Implementation Plan

Each standard must have an implementation plan. The plan must include the following elements:

What is proposed for approval /retirement- List of standards (number and title) and definitions that are proposed for approval and any associated retirements of earlier versions of the same standards or definitions.

List of functions that must comply with the requirements in the standards – The plan should include a list of the functional entities that are identified in the applicability section of the proposed standard.

Prerequisite approvals or activities — If the proposed standard cannot be implemented until some other standard is implemented or until some other activity is accomplished, the SDT must identify these prerequisites. If there are no prerequisite approvals, the SDT should include a sentence in the implementation plan that states the proposed standard is not dependent on any prerequisite approvals.

Proposed effective date or dates – The plan must list the proposed effective date or dates and must include a justification for the proposed effective date or dates. The proposed effective date or dates in the Implementation Plan must match the Proposed Effective Date section of the associated standard.

Default language:

- **Effective Date:** The first day of the first calendar quarter that is ___ months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is __ months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Recommended modifications to already approved standards – If an already approved standard has requirements that need to be modified or retired as a result of a proposed standard, the plan must include an overview of the proposed changes in the implementation plan. In addition, the plan must include a redline version of the proposed changes to the standard to show what language is being changed, and the implementation plan should include an explanation to let stakeholders know why the drafting team believes the suggested change is needed. (The red line should show proposed changes to the last approved version of the standard.)

NERC Statement of Compliance Registry Criteria

http://www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0.pdf

I. Entities that use, own or operate elements of the bulk electric system as established by NERC's approved definition of bulk electric system below are (i) owners, operators, and users of the bulk power system and (ii) candidates for registration: *"As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.4"*

Function Type	Acronym	Definition/Discussion
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a BA area, and supports Interconnection frequency in real- time.
Distribution Provider	DP	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Generator Operator	GOP	The entity that operates generating unit(s) and performs the functions of supplying energy and interconnected operations services.
Generator Owner	GO	Entity that owns and maintains generating units.
Interchange Authority	IA	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Load-Serving Entity	LSE	Secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.

Function Type	Acronym	Definition/Discussion
Planning Authority	PA	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Purchasing-Selling Entity	PSE	The entity that purchases or sells and takes title to energy, capacity, and interconnected operations services. PSE may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the reliable operation of the bulk power system, has the wide area view of the bulk power system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real- time operations. The RC has the purview that is broad enough to enable the calculation of interconnection reliability operating limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each BA's use in recovering from contingencies within the group. Scheduling energy from an adjacent BA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a RSG.
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a PA area.
Transmission Owner	TO	The entity that owns and maintains transmission facilities.

Function Type	Acronym	Definition/Discussion
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission facilities.
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

II. Entities identified in Part I above will be categorized as registration candidates who may be subject to registration under one or more appropriate functional entity types based on a comparison of the functions the entity normally performs against the following function type definitions:

III (a)Load-serving Entity:

III.a.1 Load-serving entity peak load is > 25 MW and is directly connected to the bulk power (>100 kV) system, or;

III.a.2 Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system, or;

III.a.3 Load-serving entity is designated as the responsible entity for facilities that are part of a required undervoltage load shedding (UVLS) program designed, installed, and operated for the protection of the bulk power system.

III.a.4 Distribution providers registered under the criteria in III.b.1 or III.b.2 will be registered as a load serving entity (LSE) for all load directly connected to their distribution facilities.

III(b) Distribution Provider:

III.b.1 Distribution provider system serving >25 MW of peak load that is directly connected to the bulk power system.

III.b.2 Distribution provider is the responsible entity that owns, controls, or operates facilities that are part of any of the following protection systems or programs designed, installed, and operated for the protection of the bulk power system:

- a required UFLS program.
- a required UVLS program.
- a required special protection system.

- a required transmission protection system.

IIII Generator Owner/Operator:

III.c.1 Individual generating unit > 20 MVA (gross nameplate rating) and is directly connected to the bulk power system, or;

III.c.2 Generating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating, or;

III.c.3 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a transmission operator entity's restoration plan, or;

III.c.4 Any generator, regardless of size, that is material to the reliability of the bulk power system.

III(d) Transmission Owner/Operator:

III.d.1 An entity that owns/operates an integrated transmission element associated with the bulk power system 100 kV and above, or lower voltage as defined by the Regional Entity necessary to provide for the reliable operation of the interconnected transmission grid; or

III.d.2 An entity that owns/operates a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity.

Functional Model

http://www.nerc.com/files/Functional_Model_V5_Final_Clean_2009Dec1.pdf

Functional Entity – Planning Coordinator

Definition

The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.

Introduction to the Planning Coordinator

The Planning Coordinator is responsible for assessing the longer-term reliability of its Planning Coordinator area. While the area under the purview of a Planning Coordinator may include as few as one Transmission Planner and one Resource Planner, the Planning Coordinator's scope of activities may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. Planning Coordinators work through a variety of mechanisms to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all network areas with little or no ties to others' areas, such as interconnections, are completely coordinated for planning activities.

Relationships with Other Functional Entities

1. Coordinates and collects data for system modeling from Transmission Planner, Resource Planner, and other Planning Coordinators.
2. Coordinates transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators.
3. Coordinates plans with Reliability Coordinator and other Planning Coordinators on reliability issues.
4. Receives plans from Transmission Planners and Resource Planners.
5. Collects information including:
    a. Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.
    b. Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners.
    c. Generator unit performance characteristics and capabilities from Generator Owners.
    d. Long-term capacity purchases and sales from Transmission Service Providers.

6. Collects and reviews reports on transmission and resource plan implementation from Resource Planners and Transmission Planners.
7. Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Planning Coordinator area with Transmission Planners and Resource Planners and adjacent Planning Coordinator areas, as appropriate.
8. Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system.
9. Facilitates the integration of the respective plans of the Resource Planners and Transmission Planners within the Planning Coordinator area.
    a. Reviews the integrated plan with respect to established reliability needs considering the impact on and by adjoining systems.
    b. In coordination with the Resource Planners and Transmission Planners, facilitates the development of alternative solutions for plans that do not meet those reliability needs.

Functional Entity — Transmission Planner

Definition

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

Introduction to the Transmission Planner

The Transmission Planner is responsible for assessing the longer-term (generally one year and beyond) reliability of its Transmission Planner area. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. Transmission Planners coordinate their plans with the adjoining Transmission Planners to assess impact on or by those plans. The area under the purview of a Transmission Planner may include one or more Resource Planner areas and overlap one or more adjacent Transmission Planners.

Relationships with Other Functional Entities

1. Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, Resource Planners, other Transmission Planners, Transmission Owners, and Transmission Service Providers.

2. Collects information including:

    - Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.

    - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners.

    - Generator unit performance characteristics and capabilities from Generator Owners.

    - Long-term transmission capacity purchases and sales from Transmission Service Providers

3. Informs Resource Planners and other Transmission Planners of the methodologies and tools for the simulation of the transmission system.

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

5. Coordinates the evaluation of Bulk Electric System expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

6. Reports on and coordinates its Bulk Electric System expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

7. Notifies other Transmission Planners, Transmission Owners, Transmission Operators and other entities that may be impacted of any planned Bulk Electric System changes.

8. Coordinates with Distribution Providers, Transmission Owners, Generator Owners and Load-Serving Entities in the evaluation and plans for all requests required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.

9. Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Transmission Planner area with other Transmission Planners and Resource Planners, as appropriate.

10. Coordinates and develops transfer capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners and Transmission Service Providers

11. Coordinates with Transmission Owners and Generator Owners to define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.

12. Receives maintenance schedules and construction plans from Transmission Operator or Transmission Owner for input into and evaluation of Bulk Electric System expansion plans.

Functional Entity — Resource Planner

Definition

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

Relationships with Other Functional Entities

1. Coordinates the resource models with its Planning Coordinator.
2. Coordinates with Transmission Owners and Transmission Planners on the deliverability of resources to customers.
3. Coordinates with and collects data for resource planning from the Load-Serving Entities, Generator Owners, Generator Operators, Transmission Planners, Transmission Operators, Interchange Coordinators, and Reliability Assurers.
4. Coordinates with Transmission Planners, Transmission Service Providers, Reliability Coordinators, and Planning Coordinators on resource adequacy plans.
5. Coordinates with adjoining Resource Planners within the Planning Coordinator area to avoid the double-counting of resources.
6. Reports its resource plan to the Transmission Planner and Planning Coordinator for evaluation and compliance with Reliability Standards.
7. Reports on resource plan implementation to the Transmission Planner, Planning Coordinator and Reliability Assurer.
8. Works with the Planning Coordinator and Transmission Planners to identify potential alternative transmission solutions to meet Resource Planner plans.
9. Applies methodologies and tools for the analysis and development of resource adequacy plans from the Planning Coordinator.

Functional Entity — Reliability Coordinator

Definition

The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.

Introduction to the Reliability Coordinator

The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator's wide-area view. The wide-area view includes situational awareness of its neighboring Reliability Coordinator Areas. Its scope includes both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably.

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

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

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates with other Reliability Coordinators, Transmission Planners, and Transmission Service Providers on transmission system limitations.
2. Receives facility and operational data from Generator Operators, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators.

3. Receives generation dispatch from Balancing Authorities and issues dispatch adjustments to Balancing Authorities to prevent exceeding limits within the Reliability Coordinator Area (if not resolved through market mechanisms).
4. Receives integrated operational plans from Balancing Authorities for reliability analysis of Reliability Coordinator Area.
5. Receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.
6. Develops Interconnection Reliability Operating Limits, based on Transmission Owners' and Generator Owners' specified equipment ratings, and provides them to Transmission Operators.
7. Assists Transmission Operators in calculating and coordinating System Operating Limits.
8. Provides reliability analyses to Transmission Operators, Generator Operators and Balancing Authorities in its area as well as other Reliability Coordinators.
9. Directs Generator Owners and Transmission Owners to revise generation and transmission maintenance plans that are adverse to reliability.
10. Receives balancing information from Balancing Authorities for monitoring.
11. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.
12. Provide IROLs and TTC to the Transmission Service Provider for ATC calculation.
13. Develops operating agreements or procedures with Transmission Owners.
14. Coordinates with Transmission Operators on system restoration plans, contingency plans and reliability-related services.

Real Time

15. Coordinates reliability processes and actions with and among other Reliability Coordinators.
16. Receives Real-time operational information from Balancing Authorities, Interchange Coordinators and Transmission Operators for monitoring.
17. Issues reliability alerts to Generator Operators, Transmission Operators, Transmission Service Providers, Balancing Authorities, Interchange Coordinators, Regional Entities and NERC.
18. Issues corrective actions and emergency procedures directives (e.g., curtailments or load shedding) to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange Coordinators.
19. Specifies reliability–related requirements (e.g., reactive requirements, location of operating reserves) to Balancing Authorities.
20. Receives verification of emergency procedures from Balancing Authorities.
21. Receives notification of Confirmed Interchange changes from Balancing Authorities.
22. Orders redispatch of generation by Balancing Authorities.
23. Directs use of flow control devices by Transmission Operators.

24. Responds to requests from Transmission Operators to assist in mitigating equipment overloads.

Functional Entity — Balancing Authority

Definition

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

Relationships with Other Functional Entities

Ahead of Time

1. Receives operating and availability status of generating units and operational plans and commitments from Generator Operators within the Balancing Authority Area.
2. Receives annual maintenance plans from Generator Owners within the Balancing Authority Area.
3. Receives reliability evaluations from the Reliability Coordinator.
4. Receives final approval or denial of a request for an Arranged Interchange from the Interchange Coordinators.
5. Compiles load forecasts from Load-Serving Entities.
6. Develops agreements with adjacent Balancing Authorities for ACE calculation parameters.
7. Submits integrated operational plans to the Reliability Coordinator for reliability evaluation and provides balancing information to the Reliability Coordinator for monitoring.
8. Confirms Arranged Interchange with Interchange Coordinators.
9. Confirms ramping capability with Interchange Coordinators.
10. Implements generator commitment and dispatch schedules from the Load-Serving Entities and Generator Operators who have arranged for generation within the Balancing Authority Area.
11. Acquires reliability-related services from Generator Operator.
12. Receives dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
13. Receives generator information from Generator Owners including unit maintenance schedules and retirement plans.
14. Receives information from Load-Serving Entities on self-provided reliability-related services.
15. Coordinates system restoration plans with Transmission Operator.
16. Provides generation dispatch to Reliability Coordinators.

Real Time

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

18. Receives loss allocation from Transmission Service Providers (for repayment with in-kind losses).
19. Receives Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators.
20. Receives operating information from Generator Operators.
21. Provides Real-time operational information for Reliability Coordinator monitoring.
22. Receives reliability alerts from Reliability Coordinator.
23. Complies with reliability-related requirements (e.g., reactive requirements, location of operating reserves) specified by Reliability Coordinator.
24. Verifies implementation of emergency procedures to Reliability Coordinator.
25. Informs Reliability Coordinator and Interchange Coordinators of Confirmed Interchange changes (e.g., due to generation or load interruptions) involving its Balancing Authority Area.
26. Directs resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in real time.
27. Directs Transmission Operator (or Distribution Provider) to reduce voltage or shed load if needed to ensure balance within its Balancing Authority Area.
28. Directs Generator Operators to implement redispatch for congestion management as directed by the Reliability Coordinator.
29. Implements corrective actions and emergency procedures as directed by the Reliability Coordinator.
30. Implements system restoration plans as directed by the Transmission Operator.
31. Directs Transmission Operator to implement flow control devices.
32. Receives information of Implemented Interchange and Confirmed Interchange curtailments from Interchange Coordinator.

After the hour

33. Confirms Implemented Interchange with Confirmed Interchange provided by the Interchange Coordinators after the hour for “checkout.”
34. Confirms Implemented Interchange and Confirmed Interchange with adjacent Balancing Authorities after the hour for “checkout.”

Functional Entity — Transmission Operator

Definition

The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area.

Introduction to the Transmission Operator

The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

The Transmission Operator and Reliability Coordinator have similar roles with respect to transmission operations, but different scopes. The Transmission Operator scope is narrower than the Reliability Coordinator, and the Transmission Operator does not necessarily "see" very far beyond its own boundaries. Therefore, the Transmission Operator can calculate System Operating Limits, but will not necessarily calculate Interconnection Reliability Operating Limits, which requires the wider scope of the Reliability Coordinator.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates restoration plans with Reliability Coordinator, Transmission Operators, Balancing Authorities, and Distribution Providers.
2. Receives maintenance and construction plans and schedules from the Transmission Owners and Generation Owners.
3. Receives Interconnection Reliability Operating Limits as established by the Reliability Coordinator.
4. Receives reliability evaluations from the Reliability Coordinator.
5. Develops agreements with adjacent Transmission Operators for joint transmission facilities.
6. Defines Total Transfer Capabilities and System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator.
7. Arranges for reliability-related services from Generator Operators.
8. Develops contingency plans, and monitors operations of the transmission facilities within the Transmission Operator Area control and as directed by the Reliability Coordinator.
9. Provides facility and operating information to the Reliability Coordinator.
10. Provides to the Transmission Planner information on the capability to curtail (reduce) and shed load during emergencies.

11. Provides Total Transfer Capabilities and System Operating Limits to, and coordinates Available Transfer Capability with, Transmission Service Provider.
12. Receives operating and availability status of generating units from Generation Operators including status of automatic voltage regulators.
13. Develops operating agreements or procedures with Transmission Owners.

Real Time

14. Coordinates load shedding with, or as directed by, the Reliability Coordinator.
15. Provides Real-time operations information to the Reliability Coordinator and Balancing Authority.
16. Notifies Generator Operators of transmission system problems (e.g., voltage limitations or equipment overloads that may affect generator operations).
17. Requests Reliability Coordinator to assist in mitigating equipment overloads. (e.g., redispatch, transmission loading relief).
18. Deploys reactive resources from Transmission Owners and Generator Owners to maintain acceptable voltage profiles.
19. Directs Distribution Providers to shed load if needed to ensure reliability within the Transmission Operator Area.
20. Implements flow control device operations for those ties under the Transmission Operator's purview as directed by the Balancing Authorities or Reliability Coordinator.
21. Receives reliability alerts from Reliability Coordinator.
22. Directs Balancing Authorities and Distribution Providers to implement system restoration plans.

Functional Entity — Interchange Coordinator

Definition

The functional entity that ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas.

Relationships with Other Functional Entities

Ahead of Time

1. Receives Arranged Interchange from Purchasing-Selling and Load-Serving Entities.
2. Submits request for an Arranged Interchange to become Confirmed Interchange to the Balancing Authorities and Transmission Service Providers for approvals.
3. Receives approval or denial from Transmission Service Providers of transmission arrangement(s) for Arranged Interchange.
4. Receives approval or denial from Balancing Authorities of the ability to meet ramping requirements for submitted Arranged Interchange.
5. Communicates final approval or denial of a request for an Arranged Interchange to become Confirmed interchange to the Reliability Coordinator, Balancing Authorities, Transmission Service Providers, Purchasing-Selling Entities, and Load-Serving Entities for implementation and NERC identified reliability analysis services.

Real Time

6. Receives curtailments and redispatch implementation requests from Reliability Coordinators for an Arranged Interchange.
7. Receives information on Confirmed Interchange interruptions from the Balancing Authorities and communicates the Confirmed Interchange status to Balancing Authorities, Transmission Service Providers, Reliability Coordinators, and Purchase-Selling/Load-Serving Entities.
8. Informs Transmission Service Providers, Purchasing-Selling/Load-Serving Entities, Reliability Coordinators, and Balancing Authorities of Confirmed Interchange revisions (including curtailments).

After the hour

9. Maintains and provides a record of individual Confirmed Interchange for which it coordinated with the Balancing Authorities.
10. Coordinates Confirmed Interchange with Balancing Authorities after the hour for “checkout.”

Functional Entity — Transmission Service Provider

Definition

The functional entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.

Relationships with Other Functional Entities

Ahead of Time

1. Receives Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from Planning Coordinator, Transmission Planner, Transmission Operator and Reliability Coordinator, and coordinates Available Transfer Capability with these entities and other Transmission Service Providers.
2. Receives transmission Facility Ratings from Transmission Owners.
3. Receives transmission expansion plans identified by the Planning Coordinator to help determine ability to accommodate long-term transmission service requests.
4. Approves or denies transmission service requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities.
5. Confirms validity of transmission service requests indicated in the Arranged Interchange with Interchange Coordinators.
6. Develops agreements or procedures with Transmission Owners.
7. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.

Real Time

8. Receives Confirmed Interchange revisions (including curtailments) from the Interchange Coordinators.
9. Receives reliability alerts from Reliability Coordinator.
10. Provides loss allocation to Balancing Authorities.

Functional Entity — Transmission Owner

Definition

The functional entity that owns and maintains transmission facilities.

Relationships with Other Functional Entities

1. Coordinates with Transmission Planners and the Planning Coordinator, Generator Owners, other Transmission Owners, and Load-Serving Entities desiring to connect with the Bulk Electric System.
2. Receives approved transmission expansion plans from the Transmission Planner.
3. Develops agreements or procedures with the Transmission Service Providers.
4. Develops operating agreements or procedures with the Transmission Operators, Reliability Coordinators and Distribution Providers.
5. Develops agreements with adjacent Transmission Owners for joint transmission facilities.
6. Provides transmission expansion plans and changes to the Planning Coordinator and Transmission Planners.
7. Provides transmission Facility Ratings to Transmission Operators, Reliability Coordinators, Transmission Service Providers, Distribution Providers, Transmission Planners, and Planning Coordinator.
8. Provides maintenance and construction plans and schedules to the Reliability Coordinator, Transmission Operator, and Transmission Planner.
9. Develops interconnection agreements with the Distribution Providers and Generation Owners for connecting to the Bulk Electric System.
10. Provides reactive resources to Transmission Operators.
11. Revises transmission maintenance plans as requested by the Reliability Coordinator.

Functional Entity — Distribution Provider

Definition

The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.

Introduction to the Distribution Provider

The Distribution Provider delivers electrical energy to the End-use Customer from the transmission system. For those End-use Customers who are served at transmission voltages, the Transmission Owner may also serve as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. The Distribution Provider provides the switches and recloses that could be used to shed load for emergency action.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates with Transmission Planners on transmission expansion.
2. Coordinates system restoration plans with Transmission Operator.
3. Coordinates with End-use Customers and Load-Serving Entities to identify new facility connection needs.
4. Develop interconnection agreements with Transmission Owners on a facility basis.
5. Provides operational data to Transmission Operator.
6. Coordinate with Load-Serving Entities to identify critical loads that are to be precluded from load shedding where avoidable.

Real Time

7. Implements voltage reduction and sheds load as directed by the Transmission Operator or Balancing Authority.
8. Implements system restoration plans as coordinated by the Transmission Operator.
9. Directs Load-Serving Entities to communicate requests for voluntary load curtailment.

Functional Entity — Generator Operator

Definition

The functional entity that operates generating unit(s) and performs the functions of supplying energy and reliability-related services.

Relationships with Other Functional Entities

Ahead of Time

1. Provides generation commitment plans to the Balancing Authority.
2. Provides Balancing Authority and Transmission Operators with requested amount of reliability-related services.
3. Provides operating and availability status of generating units to Balancing Authority and Transmission Operators for reliability analysis.
4. Reports status of automatic voltage or frequency regulation equipment to Transmission Operators.
5. Provides operational data to Reliability Coordinator.
6. Receives reliability analyses from Reliability Coordinator.
7. Receives notice from Purchasing-Selling Entity if Arranged Interchange approved or denied.
8. Receives reliability alerts from Reliability Coordinator.
9. Receives notification of transmission system problems from Transmission Operators.

Real Time

10. Provides Real-time operating information to the Transmission Operators and the required Balancing Authority.
11. Adjusts real and reactive power as directed by the Balancing Authority and Transmission Operators.

Functional Entity — Generator Owner

Definition

The functional entity that owns and maintains generating units.

Relationships with Other Functional Entities

1. Provides generator information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner.
2. Provides unit maintenance schedules and unit retirement plans to the Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner.
3. Develops an interconnection agreement with Transmission Owner on a facility basis.
4. Receives approval or denial of transmission service request from Transmission Service Provider.
5. Provides reliability-related services to Purchasing-Selling Entity pursuant to agreement.
6. Reports the annual maintenance plan to the Reliability Coordinator, Balancing Authority and Transmission Operator.
7. Revises the generation maintenance plans as requested by the Reliability Coordinator.

Functional Entity — Purchasing-Selling Entity

Definition

The functional entity that purchases or sells, and takes title to, energy, capacity, and reliability-related services.

Relationships with Other Functional Entities

Ahead of Time

1. Arranges for transmission service from Transmission Service Providers and makes arrangements for reliability-related services with Generator Owners or Load-Serving Entities.
2. Submits Requests For Interchange to Interchange Coordinators.
3. Notifies Generator Operators and Load-Serving Entities if Arranged Interchange requests are approved or denied.
4. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.
5. Receives load profiles and forecasts from Load-Serving Entities.

Real Time

6. Notifies Interchange Coordinators of Confirmed Interchange and Implemented Interchange cancellations or terminations.
7. Receives notice of Confirmed Interchange curtailments from Interchange Coordinator.

Functional Entity — Load-Serving Entity

Definition

The functional entity that secures energy and transmission service (and reliability-related services) to serve the electrical demand and energy requirements of its end use customers.

Relationships with Other Functional Entities

Ahead of Time

1. Submits load profiles and characteristics, plans, and forecasts as needed to the Balancing Authorities, Purchasing-Selling Entities, Planning Coordinator, Resource Planners, and Transmission Planners.
2. Identifies new facility connection needs for End-use Customers.
3. Provides generation commitments and dispatch schedules to the Balancing Authority.
4. Provides information as to self-provided reliability-related services to the Balancing Authority.
5. Provides planned purchases to the Resource Planner and Transmission Planner for system modeling and reliability evaluation.
6. Arranges for transmission service from Transmission Service Providers and makes arrangements for reliability-related services with Generator Owners or Load-Serving Entities
7. Submits Requests For Interchange to Interchange Coordinators.
8. Notifies Generator Operators if Arranged Interchange requests are approved or denied.
9. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.
10. Coordinates with Distribution Provider on identifying new facility interconnection needs.
11. Receives notification from Purchasing-Selling Entity if Arranged Interchange requests approved or denied.

Real Time

12. Receives requests from the Balancing Authority and Distribution Provider for voluntary load curtailment.
13. Communicate requests for voluntary load curtailment to end-use customers as directed by the Balancing Authority and Distribution Provider.
14. Notifies Interchange Coordinators of Confirmed Interchange cancellations or terminations.
15. Receives notice of Confirmed Interchange curtailments from Interchange Coordinator.

Version History:

Date	Page	Action
October 6, 2010	Page 28	Added description of "Scope" to clarify that the scope of the proposed requirements must be within the scope of the project identified in the SAR.
December 8, 2010	Page 4	Added language to clarify that if a requirement references an Attachment, the Attachment must be reviewed.
February 17, 2011	Page 7	Added fourth bullet under "Measures" to identify that attestations are acceptable and must be made by an individual on behalf of an entity.
	Page 14	Added default language for identification of CEA
	Page 30	Added CIP VSL Guidelines from FERC's March 18, 2010 Order Addressing VSL Assignments for CIP Reliability Standards
July15, 2011	Page 6-7	Added a sample paragraph and associated explanation advising entities that they may be asked to prove they were compliant for the entire time period since the last audit.
August 23, 2011	Page 14	Modified the language for the Compliance Enforcement Authority
	Page 14	Changed the Compliance Monitoring Process called, "Compliance Violation Investigations" to "Compliance Investigations" to match a change to the title of that process in the ROP.
September 22, 2011	Page 3	Added a sentence to the Purpose section to clarify that the requirements in the proposed standard should, collectively, support the purpose statement. Moved information into new NERC report format.
January 7, 2012	Page 7	Changed the phrase, "until found compliant" to "until mitigation is complete and approved" in the third (next to last) paragraph on this page.
January 7, 2012	Page 15	In the section called, "Compliance Enforcement Authority 1.1:"

		Replaced the following: For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority. For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority. For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority. With: The Regional Entity shall serve as the Compliance enforcement authority 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.
February 7, 2012	Page 27	Added default language for effective dates: Default language: • **Effective Date:** The first day of the first calendar quarter that is ___ months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is __ months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.