

Compliance Application Notice – 0008

PRC-005-1 R2 Basis for First Maintenance and Testing Date

Posted: April 19, 2011

Revised: November 11, 2011

Revised: April 10, 2012

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Primary Interest Groups

Compliance Enforcement Authority (CEA)¹

NERC

Regional Entity

Transmission Owner (TO)

Generation Owner (GO)

Distribution Provider (DP) that owns a transmission Protection System²

Background:

CAN-0008 was originally posted on April 19, 2011 and was revised on November 11, 2011. Industry trade associations³ jointly submitted a request for a High Level Review on February 24, 2012. NERC CEO Gerry Cauley responded on March 9, 2011, remanding CAN-0008 to NERC staff to make revisions consistent with the directions provided in the High Level Review response. This version of the CAN reflects the modifications directed in the response and supersedes the prior version of CAN-0008.

Issue: Under what circumstances are CEAs required to consider evidence dated before June 18, 2007 in connection with their review of issues related to PRC-005-1 R2?

For the purpose of aiding a CEA, this CAN provides instruction for assessing whether an entity was conducting maintenance and testing activities consistent with its Protection System maintenance and testing program starting from June 18, 2007.

¹ Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standards and requirements.

² The NERC Glossary of Terms Used in Reliability Standards defines Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry."

³ The Edison Electric Institute (EEl), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), Electricity Consumers Resource Council (ELCON), American Public Power Association (APPA), the Transmission Access Policy Study Group (TAPS) and the Large Public Power Council (LPPC).

Compliance Application

PRC-005-1 R2 provides, in pertinent part:

***R2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization^[4] on request (within 30 calendar days). The documentation of the program implementation shall include:*

***R2.1.** Evidence Protection System devices were maintained and tested within the defined intervals.*

***R2.2.** Date each Protection System device was last tested/maintained.*

Last Maintenance and Testing Date Prior to Mandatory and Effective Date

CEAs are to obtain the last date a registered entity tested and maintained its Protection System devices in order to verify compliance with PRC-005-1 R2 starting from June 18, 2007. The last maintenance or test date is necessary for a CEA to determine whether a registered entity is conducting maintenance and testing within the intervals defined by its own Protection System maintenance and testing program, including circumstances when the interval began prior to June 18, 2007, the mandatory and enforceable date of the standard.

However, CEAs are not to require registered entities to produce records of testing and maintenance activities conducted prior to June 18, 2007, because keeping such records was not mandatory at that time. Therefore, CEAs are only to require production of actual maintenance and testing records from June 18, 2007 forward.

When obtaining the last date of maintenance and testing activity prior to June 18, 2007, CEAs are to allow several options of evidence, including: (1) the registered entity's actual maintenance and testing records, if available, (2) a simple representation by the registered entity regarding the last known maintenance and testing date, or (3) the registered entity's good faith approximation of the previous maintenance and testing date, based on best available information.

If an entity elects to provide a CEA with the evidence listed in points (2) or (3) above, the CEA is to obtain the entity's description of the basis for its representation of an actual or estimated date. The basis can refer to the registered entity's actual knowledge, approximate periodicity of established maintenance and testing practices, timing of commissioning of equipment, or any other reasonable basis.

⁴ For this standard, the Regional Reliability Organization refers to the Regional Entity.

Focus on Current Intervals

A CEA is to enforce PRC-005-1 R2 only with consideration of interval dates beginning June 18, 2007 or later if the entity can demonstrate it has conducted the required maintenance and testing at least once since June 18, 2007, unless there is additional cause that warrants requesting additional evidence.

For example, if a registered entity completed its required maintenance and testing activities in November 2007 and provided appropriate maintenance and testing records, the CEA is to accept that evidence and is not to request the registered entity's prior maintenance and testing date if it occurred before June 18, 2007. However, a CEA is to request evidence of the registered entity's last maintenance and testing date if it occurred after June 18, 2007.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from April 19, 2011, regardless of the start date of the violation. Regional and Enforcement staff are to review Possible Violations (PV) in process and 1) evaluate dismissal of any PV that was identified according to the instruction in the prior version of this CAN that is inconsistent with this CAN and 2) apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

This version of the CAN will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN, or a future High Level Review remands the CAN for modification or withdrawal.

Evidence of Compliance

A CEA is to obtain one or more of the following as evidence of the last date of maintenance and testing activity that occurred prior to June 18, 2007 (if such evidence is necessary as discussed above):

1. Actual maintenance and testing records, if available;
2. A simple representation by the registered entity regarding the last known maintenance and testing date and the registered entity's description of the basis for its representation of an actual or estimated date. The basis can refer to the registered entity's actual knowledge, approximate periodicity of established maintenance and testing practices, timing of commissioning of equipment, or any other reasonable basis; or
3. The registered entity's good faith approximation of the previous maintenance and testing date based on best available information and the registered entity's description of the basis for its representation of an actual or estimated date. The basis can refer to the registered entity's actual knowledge, approximate periodicity of established maintenance and testing practices, timing of commissioning of equipment, or any other reasonable basis.

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Revision History

Posted Date	Action	Revision
April 19, 2011	Posted Final CAN	
November 11, 2011	Posted Revised CAN	Revised target audience to CEAs
February 24, 2012	High-Level Review Received	
March 9, 2012	Remanded to NERC staff for further work	
April 10, 2012	Posted Revised CAN	Made modifications as directed by NERC CEO High Level of Review

Compliance Application Notice (CAN) High-Level Review Request Form

Date: February 24, 2012

Requesting Entity/Trade Organization (list all represented Entities or attach a list): The Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the Electric Power Supply Association (EPSA), Electricity Consumers Resource Council (ELCON), American Public Power Association (APPA), the Transmission Access Policy Study Group (TAPS) and the Large Public Power Council (LPPC) (collectively, the Trade Associations).

CAN Number: 0008

Standard and Requirement: PRC-005-1 Requirement R2

Please indicate the nature of your request for review:

Jurisdictional _____ Other Legal ☒ Beyond Scope _____ Technical _____
Errata/Grammar _____ Creates an evidentiary burden ☒ Other _____

For NERC CEO Review

1. Please fully describe your reason for requesting the NERC CEO higher level review.

The Trade Associations (The Trades) and their member companies seek higher level review of Compliance Application Notice 0008 ("CAN-0008") because the document as written directs Compliance Enforcement Authorities ("CEAs") to apply PRC-005-1, R2 in a manner that is unlawful in that such application constitutes prohibited retroactive rulemaking and violates the requirements of due process. Moreover, CAN-0008's requirement that registered entities provide evidence of maintenance and testing required by PRC-005-1, R2 prior to the effective date of the Standard, prior to NERC's adoption of PRC-005-1 and PRC-005-0, and even prior to the date NERC was authorized by FERC to enforce standards does not promote reliability of the BES.

The Trades submit that CAN-0008 unlawfully directs CEAs, including Regional Entities, to request evidence from registered entities far in advance of the June 18, 2007 effective date of PRC-005-1, prior to NERC's adoption of PRC-005-1, and even prior to NERC's adoption of PRC-005-0. The impact of this compliance guidance, if left unchecked, would be to direct CEAs to penalize entities for actions taken prior to the effective date of the Standard (and in fact even prior to NERC's adoption of the Standard) which constitutes prohibited retroactive rulemaking and violates due process.

In addition, requiring, as CAN-0008 directs, registered entities to provide evidence that maintenance and testing was performed for intervals reaching back prior to the June 18, 2007 effective date of the Standard does nothing to promote reliability of the BES. In the case where a registered entity can demonstrate that it has performed the required maintenance and testing within the interval defined in its program, the CAN requirement to provide evidence that the same maintenance and testing was performed for a prior interval does nothing to promote reliability of the BES. The Trades submit that what really matters is not what was done prior to the approval of the Standard, but whether the maintenance and testing program required by the Standard is performed during the registered entity's first interval as defined by the effective date of the Standard.

Moreover, requiring registered entities to provide evidence from time periods when no such requirement existed creates an undue evidentiary burden with no improvement to reliability.

Example:

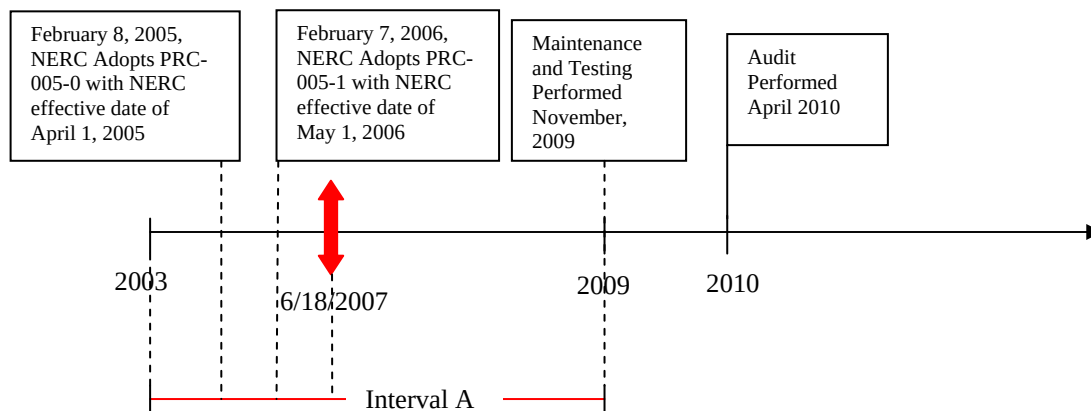
CAN-0008 instructs CEAs to review evidence that maintenance and testing was done for intervals that include periods prior to the June 18, 2007 effective date of PRC-005-1. In fact, CAN-0008 instructs CEAs to request such evidence for time periods prior to NERC's adoption of PRC-005-1 in 2006¹ and, in this example, prior to even the adoption of PRC-005-0. CAN-0008 further states: "To the extent that prior maintenance/test dates for specific devices occurred prior to June 18, 2007, the CEA is instructed to request evidence of such maintenance/testing" CAN-0008 provides the following example:

Example 1

In this example, the registered entity has its first audit on April 10, 2010; it has a documented maintenance and testing interval of six years, and it conducted maintenance and testing on its equipment in November 2009. CEAs are to verify:

- 1) evidence of the registered entity's maintenance and testing activities in November 2009 (demonstrating compliance beginning in November 2009), and
- 2) evidence or records sufficient to demonstrate that the registered entity's prior maintenance and testing activity occurred in or after November 2003 (to show compliance between June 18, 2007 and November 2009).

¹ PRC-005-1, NERC Effective Date May 1, 2006

Figure 1

Using Example 1 and the timeline provided (Figure 1) above we illustrate our concern. We note, Example 1 states that, assuming an audit occurred in 2010 and equipment was on a six-year maintenance and testing interval with the latest testing having occurred in 2009, CEAs are to require evidence to demonstrate maintenance and testing activity occurred in or after 2003 (Figure1, Interval A).

As can be seen in this example, the CAN finds that it is not sufficient for the entity to demonstrate that they were in full auditable compliance from the point of enforcement (i.e., the effective date of the Standard) moving forward. CAN-0008 would require registered entities to submit records demonstrating that they performed similar testing and maintenance in 2003, nearly 3 ½ years prior to the date of enforcement, three years prior to NERC's adoption of PRC-005-1, and even two years prior to NERC's adoption of PRC-005-0. In Example 1, the registered entity can demonstrate full compliance in 2009 – the maintenance and testing program was in place by the June 18, 2007 effective date including set intervals, interval bases, and in this case, confirmation that maintenance and testing occurred according to the program. This scenario should fully satisfy the Standard for the interval established on the effective date of the Standard.

Further, the CAN language is contrary to the underpinnings of the standard language. The standard language does not state or imply that that evidence of testing or maintenance was to be required on the effective date. There is no discussion or assumption that a demonstration of testing or maintenance was to be available on June 18, 2007 for testing or maintenance performed prior to or on June 18, 2007. The measures within PRC-005-1 state:

M2. *Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated*

Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

By stating that implementation is part of R2 recognizes that the imposition of a mandatory and enforceable standard created a new program including collection of interval evidence going forward.

The Trades are also concerned that, during a time when NERC is utilizing an enforcement mechanism such as Find, Fix, Track and Report (FFT) to focus compliance resources on the most significant risks to BES reliability, issuing compliance guidance such as that provided in CAN-0008 is counter to that goal. The above example suggests that the entity was fully in compliance with its current (as of the April 2010 audit and demonstrated by the 2009 evidence) testing and maintenance practices, but out of compliance due to lack of 2003 testing evidence. There is absolutely no improvement to reliability to require the additional evidence that the same maintenance and testing was performed more than three years earlier, as required by CAN-0008. The look back is purely a compliance burden. Compliance actions along these lines undermine NERC's stated emphasis on reliability. They risk filling the compliance action logs with burden contrary to efforts to build credible enforcement of reliability concerns.

Application of CAN-0008 Constitutes Prohibited Retroactive Rulemaking

It is well-established that an administrative agency² cannot apply its rules retroactively, unless there is clear congressional authorization to do so.³ In *Bowen*, the Court expressly stated:

It is axiomatic that an administrative agency's power to promulgate legislative regulations is limited to the authority delegated by Congress.

* * * * *

Retroactivity is not favored in the law. Thus, congressional enactments and administrative rules will not be construed to have retroactive effect unless their language requires this result. *E.g.*, *Greene v. United States*, 376 U.S. 149, 160 (1964); *Claridge Apartments Co. v. Commissioner*, 323 U.S. 141, 164 (1944); *Miller v. United States*, 294 U.S. 435, 439 (1935); *United States v. Magnolia Petroleum Co.*, 276 U.S. 160, 162-163 (1928). By the same principle, a statutory grant of legislative rulemaking authority will not, as a general matter, be understood to encompass the power to promulgate retroactive rules unless that power is conveyed by

² The Reliability Standards are administered by the Federal Energy Regulatory Commission ("FERC"). FERC has delegated enforcement of the Reliability Standards to NERC, and NERC has in turn delegated enforcement to Regional Entities. FERC retains ultimate oversight of the enforcement of Reliability Standards.

³ See generally *Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208-09 (1988); *Northwest Hospital Corp. v. Sebelius*, 657 F.3d 1 (D.C. Cir. 2011) (stating: "It is well settled that an agency may not promulgate a retroactive rule absent express congressional authorization.").

Congress in express terms. See *Brimstone R. Co. v. United States*, 276 U.S. 104, 122 (1928) (“The power to require readjustment for the past is drastic. It . . . ought not to be extended so as to permit unreasonably harsh action without very plain words”). Even where some substantial justification for retroactive rulemaking is presented, courts should be reluctant to find such authority absent an express statutory grant.⁴

With regard to the Reliability Standards, the relevant congressional authorization is found in the Energy Policy Act of 2005.⁵ EAct 2005 authorized the ERO (NERC) to file proposed Reliability Standards with FERC for approval. The ERO is further authorized to enforce the FERC-approved Reliability Standards. However, EAct 2005 provided no congressional authorization for the Reliability Standards to be applied retroactively.⁶ Federal Power Act section 215(d)(2) provides that “[a] proposed standard or modification shall take effect upon approval by the Commission” while section 215(e)(1) makes clear that Commission approval is a pre-condition for any action by the ERO to enforce compliance with a reliability standard.

The D.C. Circuit has set out a two step test to determine whether a rule is impermissibly retroactive. First, the court “looks to see whether it effects a substantive change from the agency’s prior regulation or practice.”⁷ Second, if the rule does effect a substantive change from the agency’s prior regulation or practice, the court “examine[s] its impact if any on the legal consequences of prior conduct.”⁸

PRC-005-1, R2 was first adopted by NERC in 2006 with a NERC effective date of May 1, 2006. In Order No. 693, the Commission approved PRC-005-1, R2 to become effective June 18, 2007. From May 1, 2006 to June 18, 2007, FERC indicated that it would enforce PRC-005-1, R2 as good utility practice under a public utility’s Open Access Transmission Tariff.⁹ However, during this period, PRC-005-1 was not enforceable by NERC or the Regional Entities, nor were registered entities subject to penalties up to \$1 million per day per violation of PRC-005-1, R2.¹⁰ FERC’s issuance of Order No. 693 subjects registered entities to a new regulatory program with substantial new potential penalties. Accordingly, FERC’s approval of PRC-005-1 in Order No. 693 is a substantive change from the Commission’s prior

⁴ *Bowen*, 488 U.S. at 208-09.

⁵ Section 1211 of the Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005), codified at 16 U.S.C. § 824o (“EAct 2005”).

⁶ The Commission’s policy on enforcement, which NERC has incorporated in its Sanction Guidelines, expressly recognized that, under EAct2005, the Commission’s new and enhanced civil penalty authority was prospective only. *Enforcement of Statutes, Orders, Rules, and Regulations*, 113 FERC ¶ 61,068, P 14 n.22 (2005). Where, in EAct 2005, Congress intended to authorize an agency to apply regulations retroactively it did so expressly. Specifically, in section 344 of EAct 2005, Congress expressly authorized the Secretary of the Interior to promulgate regulations and to apply those regulations retroactively. Congress did not authorize the retroactive application of the Reliability Standards. See generally 16 U.S.C. § 824o.

⁷ *Northwest Hospital Corp.*, 657 F.3d at 14 (quoting *Nat’l Mining Ass’n v. Dep’t of Labor*, 292 F.3d 849, 860 (D.C. Cir. 2002).

⁸ See *Northwest Hospital Corp.*, 657 F.3d at 14; see also *Bowen*, 488 U.S. at 208-09.

⁹ See *supra* note 3.

¹⁰ *Id.*

regulation and practice. Second, there is substantial impact on the legal consequences of prior conduct. Specifically, to the extent that a CEA determines that a registered entity is not in compliance with PRC-005-1, R2 for intervals that include periods that predate the effective date of PRC-005-1, R2, the registered entity may be subject to substantial penalties up to \$1 million per day per violation for something it was not then required to comply with. For these reasons, application of PRC-005-1 to intervals that include periods prior to the June 18, 2007 effective date of that reliability standard is “substantively inconsistent with . . . prior agency practice and attaches new legal consequences to events completed before its enactment. . . .”¹¹

To the extent that CAN-0008 requires registered entities to provide evidence of maintenance and testing required by PRC-005-1, R2 for intervals that include periods prior to the effective date of PRC-005-1, R2, such application of PRC-005-1, R2 constitutes a prohibited retroactive rulemaking.¹²

Application of CAN-0008 Constitutes a Denial of Due Process

Traditional concepts of due process incorporated into administrative law preclude an agency from assessing penalties for violating a rule without first providing adequate notice of the substance of the rule.¹³ To determine whether a regulated party was provided fair notice, depends on “whether the regulated party received, or should have received notice of the agency’s interpretation in the most obvious way of all: by reading the regulations.”¹⁴ If by reviewing the regulations and other public statements issued by the agency, the regulated party acting in good faith would be able to identify, with ascertainable certainty, the standards with which the agency expects parties to conform, the agency has provided the regulated party fair notice.¹⁵

CAN-0008 instructs CEAs to require evidence of maintenance and testing required by PRC-005-1, R2 for intervals that include periods that are not only prior to the June 18, 2007 effective date of the standard but also (i) prior to NERC’s adoption of PRC-005-1, R2, which for the first time required evidence that Protection System devices were maintained and tested within the intervals defined in the registered

¹¹ *Northwest Hospital Corp.*, 657 F.3d at 14 (quoting *Arkema Inc. v. EPA*, 618 F.3d 1, 11 (D.C. Cir. 2006) (internal quotation marks omitted)).

¹² *Northwest Hospital Corp.*, 657 F.3d at 14. Even assuming, without conceding, that Order No. 693 did not effect a substantive change from the agency’s prior regulation or practice, there can be no dispute that NERC’s adoption of PRC-005-1, which for the first time required evidence that Protection System devices were maintained and tested within the intervals defined in the registered entity’s program, did effect a substantive change from the agency’s prior regulation or practice. Accordingly, at most the intervals for which a CEA can require evidence of maintenance and testing under PRC-005-1, R2 cannot start prior to May 1, 2006 (the NERC effective date of PRC-005-1). However, as discussed herein, CAN-0008 instructs CEAs to require evidence of maintenance and testing for periods that are prior to May 1, 2006 and even prior to NERC’s adoption of PRC-005-0.

¹³ *Howmet Corp. v. Env’tl. Protection Agency*, 614 F.3d 544, 553 (D.C. Cir. 2010) (citing *Satellite Broad. Co., Inc. v. FCC*, 824 F.2d 1, 3 (D.C. Cir. 1987)).

¹⁴ *Howmet Corp.*, 614 F.3d at 553 (quoting *General Elec. Co. v. Env’tl. Protection Agency*, 53 F.3d 1324, 1329 (D.C. Cir. 1995)).

¹⁵ *Id.* at 553-54.

entity's program, and (ii) even before NERC's adoption of PRC-005-0. Registered entities did not have any notice that NERC or a Regional Entity could require evidence of maintenance and testing prior to the June 18, 2007 effective date of PRC-005-1 or that they would be subject to penalties up to \$1 million per day per violation if they could not provide such evidence.¹⁶

CAN-0008 purports to instruct CEAs to find registered entities are not in compliance with PRC-005-1, R2, and therefore subject such registered entities to substantial penalties under section 215 of the FPA, if such registered entities cannot provide evidence that maintenance and testing required by PRC-005-1, R2 was performed prior the June 18, 2007 effective date of the Reliability Standard and, in some cases, prior to (i) NERC's adoption of PRC-005-1, R2, and (ii) NERC's adoption of PRC-005-0. CAN-0008's instruction to CEAs to require evidence of maintenance and testing required by PRC-005-1, R2 for intervals that include periods prior to the June 18, 2007 effective date of PRC-005-1 violates traditional concepts of due process which require adequate notice of a rule before such rule can be enforced.¹⁷

2. If you believe the compliance application should be modified, please provide your recommendation for modification.

CAN-0008 should be withdrawn or modified to make clear that the intervals for which a CEA can require the registered entity to provide evidence under PRC-005-1, R2 started on the Reliability Standard June 18, 2007 effective date and should only be applied moving forward. Based on the retroactive and due process arguments articulated above, CEAs cannot request evidence that maintenance and testing was performed during an interval prior to June 18, 2007. While the arguments herein speak to one specific scenario (Figure 1), there are many other scenarios in which this same issue of retroactive application of PRC-005-1, R2 may arise. Accordingly, in submitting this appeal, the Trades do not request a determination specific to the illustration in Figure 1. Rather, the

¹⁶ It is worth noting that, prior to CAN-0008, at least one Regional Entity, WECC, initially recognized that it could only apply the Reliability Standards prospectively. Specifically, in public presentations, WECC stated: "To be sanctionable, violation must be based only on data and records after the standard became mandatory." PowerPoint Presentation by Steve McCoy, Director of Compliance, entitled "NERC Compliance Monitoring and Enforcement: Reliability Standards Workshops, April 2007". For convenience, a copy of the cover page for the presentation and the relevant page that includes the statement "To be sanctionable, violation must be based only on data and records after the standard became mandatory" are attached and included with the appeal as Exhibit A. Notwithstanding that initial recognition, WECC has required registered entities to provide in its compliance audits evidence of maintenance and testing prior to the effective date of PRC-005-1. For example, in an audit performed on July 9-11, 2007, within weeks of the effective date of PRC-005-1, WECC found one registered entity (Avista) not in compliance with PRC-005-1, R2 because it was behind schedule for of maintenance and testing for certain relays. See NERC NOP filed in FERC Docket No. NP10-26. Assuming the registered entity's program required maintenance and testing of such equipment on a four-year interval, the alleged violation of PRC-005-1 was based on an allegation that the registered entity could not demonstrate that it performed the maintenance and testing between July 2003 and July 2007. However, given that PRC-005-1 was not effective until June 18, 2007, it was impossible for the registered entity to be behind schedule on such maintenance and testing weeks after the effective date. In fact, neither PRC-005-1 nor PRC-005-0 were even adopted by NERC in 2004.

¹⁷ See *Howmet Corp.*, 614 F.3d at 553.

Trades are of the position that evidence of maintenance and testing prior to June 18, 2007 cannot and should not be required irrespective of the circumstances at issue. As such, only a withdrawal of CAN-0008 or a modification of the CAN to prohibit CEAs from requiring PRC-005-1, R2 evidence prior to June 18, 2007 will suffice.

3. Add any additional comments here.

The Trades are concerned that registered entities' exposure to potential violations of PRC-005-1, Requirement R2 will continue indefinitely as new equipment is added to registered entities' Protection System maintenance and testing program rendering such equipment subject to the retroactive application of PRC-005-1, R2 as presently directed by CAN-0008. For example on December 23, 2008, the Western Electricity Coordinating Council ("WECC") issued "WECC Compliance Bulletin Standard PRC-005-1 v2" which attempted to answer the previously open question: "Which auxiliary relays or sensing devices are covered by PRC-005-1 and which are not?" As a result of the 2008 Bulletin, some registered entities added certain equipment to their Protection System maintenance and testing programs. Even assuming that such equipment was tested and maintained in accordance with PRC-005-1 at or around the time it was added to the registered entities Protection System maintenance and testing program, there is the lingering potential that the registered entity will be found to be out of compliance if it cannot demonstrate that the maintenance and testing was performed during the interval ending when equipment was added to the program and the maintenance and testing was performed. Thus, the issue of retroactive application of PRC-005-1, R2 will not be resolved by the mere passage of time, but rather will be ongoing and capable of being applied in a similar manner in the future.

In addition to withdrawing or remanding CAN-0008, the Trades strongly suggest that NERC must make it clear that, for purposes of compliance with PRC-005-1, Requirement R2, testing and maintenance intervals for equipment added to registered entities' programs, including those in response to any Bulletin, Announcements or Alerts, start when such equipment is added to the registered entities' programs and that CEAs cannot request evidence of maintenance and testing for periods prior to the date such equipment was added to the registered entities' programs as directed by either the ERO or Regional Entity.

For NERC BOTCC Review

Note: NERC CEO Review must be completed prior to submission for NERC BOTCC Review

1. Please fully describe your reason for requesting the BOTCC higher level review (i.e. the basis of disagreement with the CEO determination or any remaining issue to be resolved).
2. Add any additional comments here.

(For NERC use only):

Level of Review: CEO _____ Date: _____ BOTCC _____ Date: _____

NERC Chief Executive Officer review date:
Disposition of CEO review

NERC Board of Trustees Compliance Committee (BOTCC) review date, if applicable:
Disposition of BOTCC review, if applicable

* Some of the presentations have been modified or updated due to either regulatory updates after the first workshop in Orlando, or to meet stakeholder requests because of the wide range of informational needs.

NERC Compliance Monitoring and Enforcement

Reliability Standards Workshops April 2007

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

“Carry Over and New Violations”

- Violations that are not fully mitigated on day one of mandatory penalties:
 - Will become “new” violations
 - Sanctions and penalties could be levied as if it were a new violation on day one
 - An in-place, approved, Mitigation Plan could eliminate a sanction and penalty
- New Violations
 - To be sanctionable, violation must be based only on data and records after the standard became mandatory.

High-Level Review of CAN-0008 – Basis for First Maintenance and Testing Date

Review by NERC President and Chief Executive Officer

Executive Summary and Finding

The NERC President and Chief Executive Officer (NERC CEO) has been asked to conduct a high-level review of CAN-0008 to determine if its application constitutes prohibited retroactive rulemaking, violates the requirements of due process, and does not promote reliability of the bulk power system. Upon consideration of the issues raised, the NERC CEO remands CAN-0008 to NERC staff to make revisions consistent with the directions provided herein.

Specifically, the NERC CEO finds that the instructions in CAN-0008 requiring the Compliance Enforcement Authority (CEA) to verify corroborating material evidence predating June 18, 2007 as the only means of verifying the basis for a maintenance interval beginning prior to June 18, 2007 is inappropriate. Although such evidence would be one option for demonstrating a basis for the start date of a maintenance interval predating June 18, 2007, such evidence should not be required as the exclusive method, particularly if such evidence is not available or the previous maintenance date prior to June 18, 2007 can only be estimated. CEAs seeking to assess the basis for determination of a date of maintenance and testing activity prior to June 18, 2007 should allow registered entities several options, including, if necessary, good faith estimates of the last dates of maintenance and testing. Moreover, the CAN should instruct CEAs to focus on current intervals rather than prior intervals when appropriate evidence exists regarding maintenance and testing activities completed post June 18, 2007. These revisions are discussed below.

Background

On February 24, 2012, the Edison Electric Institute, the National Rural Electric Cooperative Association, the Electric Power Supply Association, the Electricity Consumers Resource Council, the American Public Power Association, the Transmission Access Policy Study Group and the Large Public Power Council (collectively, the Trade Associations or Trades) requested that the NERC CEO review CAN-0008.

CAN-0008 provides instruction for CEAs in assessing whether a registered entity was following its Protection System maintenance and testing program starting from the later of June 18, 2007 or the entity's registration date. It directs CEAs to obtain the last date in which a registered entity tested and maintained its Protection System devices in order to verify compliance with PRC-005-1 R2. The CAN states that the last maintenance or test date is required to determine whether a registered entity is conducting maintenance and testing within the intervals defined by the registered entity's own Protection System maintenance and testing program, including in circumstances when the interval

began prior to June 18, 2007. In addition, the CAN directs CEAs to validate the dates supplied by the registered entity. The CAN also provides examples of the types of corroborating evidence that would be accepted in connection with pre-June 18, 2007 maintenance and testing dates and provides that the verification should cover the entire audit period.

At issue is Requirement 2 of PRC-005 which states:

R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). *The documentation of the program implementation shall include:*

R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.

R2.2. Date each Protection System device was last tested/maintained.

(underline and italics added).

Request for High-Level Review and Analysis

1 – Reason for requesting NERC CEO higher level review

The Trades raise two primary concerns regarding CAN-0008 – retroactive rulemaking and due process, which are discussed below.

Specifically, the Trades state that the CAN unlawfully directs CEAs to request evidence from registered entities in advance of the June 18, 2007 effective date of PRC-005-1. According to the Trades, this directive has the effect of penalizing entities for actions taken prior to the effective date of the standard and constitutes prohibited retroactive rulemaking and violates due process.

In addition, the Trades state that the requirement to provide evidence of maintenance and testing for prior intervals does not promote the reliability of the bulk power system.

The Trades provide examples of the application of the CAN and conclude that the direction to CEAs in the CAN could require entities to provide evidence of maintenance and testing records related to periods prior to NERC's adoption of PRC-005-1 in 2006 and prior to the adoption of PRC-005-0 in February 8, 2005.

The Trades also state that the standard language does not state or imply that evidence of testing or maintenance was to be required on the effective date of the standard and that the collection of interval evidence was part of a new requirement introduced by the standard.

Finally, the Trades express a concern that the directive in the CAN regarding compliance with prior intervals is counter to the goal of focusing compliance on the most significant risks to the reliability of the bulk power system.

Retroactive Rulemaking

The Trades note that PRC-005-1, R2 was first adopted by NERC in 2006 with a NERC effective date of May 1, 2006. The standard was subsequently approved by FERC in Order No. 693 to become effective on June 18, 2007. The Trades also note that from May 1, 2006 to June 18, 2007, FERC indicated that it would enforce PRC-005-1, R2 as good utility practice under a public utility's open access transmission tariff. However, the Trades state that, at that time, the standard was not enforceable by NERC or Regional Entities and not subject to monetary penalties. The Trades conclude that FERC's approval of the standard in Order No. 693 is a substantive change from FERC's prior regulation and practice and that there is a substantial impact on the legal consequences of prior conduct. Consequently, the Trades claim that to the extent that the CAN requires registered entities to provide evidence of maintenance and testing required by the standard for intervals that include periods prior to the effective date of the standard, such application constitutes a prohibited retroactive rulemaking.

Due Process

The Trades also state that the CAN violates traditional concepts of due process which require adequate notice of a rule before such a rule can be enforced.

NERC CEO Analysis and Determination

The NERC CEO finds that registered entities should not be required to produce records of testing and maintenance activities conducted prior to June 18, 2007, because keeping such records was not mandatory at that time. Therefore, CEAs should require production of actual maintenance and testing records only from June 18, 2007 forward. However, the NERC CEO finds that registered entities are required to identify the last maintenance and testing dates for Protection System devices that relate to intervals which continue after June 18, 2007, even if an interval start date occurred before June 18, 2007. This is necessary to demonstrate the basis for the interval adopted for Protection System devices as required under R1.1 and to demonstrate the equipment is being maintained and tested as needed for a reliable bulk power system in the post June 18, 2007 portion of the maintenance interval.

The date of the last testing and maintenance activity that precedes June 18, 2007 can be demonstrated through either (a) material evidence of actual maintenance and testing as suggested by current language in CAN-0008, (2) a simple representation by the registered entity regarding the last known maintenance and testing date, or (3) the registered entity's good faith approximation of the previous maintenance and testing date, based on best available information. An entity that does not have records of actual maintenance and testing should also describe the basis for its representation of an actual or estimated date. The basis can refer to the registered entity's actual knowledge, approximate periodicity of established maintenance and testing practices, timing of commissioning of equipment, or any other reasonable basis.

The NERC CEO also finds that in cases where a registered entity is able to demonstrate, through evidence of actual maintenance and testing, that it has performed the required maintenance and testing after June 18, 2007, then there is no further reliability benefit in assessing maintenance intervals that include periods before June 18, 2007. Therefore, if the required maintenance has been completed since June 18, 2007, the CEA should not without additional cause request evidence regarding prior maintenance and testing periods which include dates preceding June 18, 2007. For example, if the required maintenance and testing were completed in November 2007, with appropriate documentation, auditing prior maintenance and testing periods that include dates before June 18, 2007 does not serve a beneficial reliability purpose. The CEA should enforce the requirement only with consideration of interval dates beginning June 18, 2007 or later if the entity has conducted the required maintenance since June 18, 2007. This principle would not apply if a possible violation was identified first and then the maintenance conducted after the fact to remedy the violation.

The NERC CEO disagrees with the Trades' position that maintenance and testing activity conducted prior to June 18, 2007 is not relevant to the reliability of the bulk power system. As explained, the date of maintenance and testing conducted prior to June 18, 2007 is important to allow the ERO to determine that a registered entity is conducting maintenance and testing in accordance with its defined intervals and that the defined intervals are not based on an arbitrary schedule. Therefore, although requiring material evidence of maintenance and testing conducted prior to June 18, 2007 is inappropriate, knowing the date of that previous maintenance and testing, even if estimated and unsubstantiated by material evidence, is relevant to determining that equipment is being maintained and tested as required post June 18, 2007. For example, on June 19, 2007 a device with a four-year maintenance and testing cycle and an estimated previous activity date of June 2002 (five years) presented a risk to the bulk power system on June 19, 2007 and constituted a violation of an enforceable requirement.

Moreover, the NERC CEO finds that the reference to the history of PRC-005, from May 1, 2006 does not support the notion that registered entities did not have notice of the requirements being adopted. To the contrary, history shows that most of the industry was made aware of, and that some were under an obligation to follow, these requirements from that time forward as good utility practice (even if

they were not enforceable by NERC or the Regional Entities). Furthermore, PRC-005 Version 0 was adopted by the NERC board and made effective as a NERC standard on April 1, 2005 with substantively the same requirements and measures specifying the need to keep maintenance and testing records. NERC is not proposing to enforce the requirements of PRC-005-1 prior to June 18, 2007, but it is reasonable to expect that entities were at least made aware of the pending requirements beginning May 1, 2006, if not April 1, 2005, and would have some type of record of the timing of the maintenance and testing activity conducted from then forward. As discussed above, for maintenance and testing activity conducted prior to June 18, 2007, NERC will require the timing to be noted, and a basis for determination of that time – however, the basis may be documented or estimated.

With this approach, registered entities will not be penalized for actions taken or not taken prior to June 18, 2007. However, failure to perform maintenance and testing beginning June 18, 2007 with the entity's own maintenance plan and with the entity's own estimated interval requirement could constitute a violation subject to penalty.

2 – Recommendation for modification

The Trades request that the CAN be withdrawn or modified to make clear that the intervals for which a CEA can require the registered entity to provide evidence under PRC-005-1 R2 started on June 18, 2007 and should only be applied moving forward.

NERC CEO Analysis and Determination

As indicated above, the NERC CEO remands the CAN to NERC staff for revisions consistent with the discussion herein. Specifically, as discussed above, the instructions in CAN-0008 regarding the type of evidence to be required should be revised to allow registered entities to provide estimated last dates of maintenance and testing if those dates occur prior to June 18, 2007.

The Trades' request that only maintenance and testing intervals that start after June 18, 2007 should be considered in enforcement of the standard indicates a misunderstanding of the standard and the rules in effect. The standard and the rules in effect require maintenance activities to be current with the maintenance plan beginning on June 18, 2007, not some later date determined by the entity's plan.

3 – Additional comments

The Trades also request that NERC clarify that testing and maintenance intervals for equipment added to a registered entity's maintenance and testing programs, including those in response to any bulletin, announcements or alerts, start when such equipment is added to the registered entity's programs and that CEAs cannot request evidence of maintenance and testing for periods prior to the date such equipment was added to the registered entity's programs as directed by the ERO or Regional Entity.

NERC CEO Analysis and Determination

The NERC CEO finds that CEAs are in the best position to consider the individual circumstances of each matter with regard to new equipment or expanded scope of equipment covered. In general, however, matters involving newly added equipment should be resolved through the application of the same principles discussed herein so as to avoid applying standards and rules retroactively.

Conclusion

For the reasons stated above, CAN-0008 is remanded to staff for further work. The NERC CEO finds that the instructions in CAN-0008 requiring the CEA to verify corroborating material evidence predating June 18, 2007 as the only means of verifying the basis for a maintenance interval beginning prior to June 18, 2007 is inappropriate. Staff is directed to revise CAN-0008 in accordance with the findings and principles herein. CAN-0008 is determined to not be applicable as instructions to CEAs until conforming corrections are completed.

Compliance Application Notice – 0008

PRC-005-1 R2 Basis for First Maintenance and Testing Date

Posted: April 19, 2011

Revised: November 11, 2011

Primary Interest Groups

Compliance Enforcement Authority (CEA)¹

NERC

Regional Entity

Transmission Owner (TO)

Generation Owner (GO)

Distribution Provider (DP) that owns a transmission Protection System

Issue: Under what circumstances are CEAs required to consider evidence dated before June 18, 2007 in connection with their review of issues related to PRC-005-1 R2?

For the purpose of aiding a CEA, this CAN provides instruction for assessing whether an entity was following its Protection System² maintenance and testing program starting from June 18, 2007.

Compliance Application

CEAs are to obtain the last date a registered entity tested and maintained its Protection System devices in order to verify compliance with PRC-005-1 R2. Compliance with PRC-005-1 R2 is to be verified starting from June 18, 2007.

PRC-005-1 R2 provides, in pertinent part:

R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization^[3] on request (within 30 calendar days). The documentation of the program implementation shall include:

R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.

R2.2. Date each Protection System device was last tested/maintained.

¹ Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standards and requirements.

² The NERC Glossary of Terms Used in Reliability Standards defines Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry."

³ For this standard, the Regional Reliability Organization refers to the Regional Entity.

The last maintenance or test date is necessary for a CEA to determine whether a registered entity is conducting maintenance and testing within the intervals defined by its own Protection System maintenance and testing program, including in circumstances when the interval began prior to June 18, 2007, the mandatory and enforceable date of the standard.

A CEA is to verify that the registered entity included the date each Protection System device was last tested and maintained in its documentation of the registered entity's program implementation, and a CEA is to validate these documented dates.

To the extent that prior maintenance/test dates for specific devices occurred prior to June 18, 2007, the CEA is instructed to request evidence of such maintenance/testing because:

- 1) the evidence documents the last date the registered entity performed maintenance and testing if that occurred prior to June 18, 2007,
- 2) the evidence demonstrates that the registered entity was following its program starting from June 18, 2007, and
- 3) the evidence provides the basis for the registered entity's first post-June 18, 2007 maintenance and testing date.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from April 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,⁴ a CEA is to apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance

A CEA is to obtain corroborating evidence regarding the pre-June 18, 2007 maintenance and testing date from the registered entity including, but not limited to:

- invoices
- maintenance reports
- emails

⁴ "Initiated" means that a registered entity has received notification of the upcoming audit.

- orders for parts
- hand-written notes
- an attestation with corroborating evidence

Additionally, CEAs are to verify evidence of when the last conducted maintenance and testing was performed on a registered entity's equipment over the entire audit period. Some examples are as follows:

Example 1

In this example, the registered entity has its first audit on April 10, 2010; it has a documented maintenance and testing interval of six years, and it conducted maintenance and testing on its equipment in November 2009. CEAs are to verify:

- 1) evidence of the registered entity's maintenance and testing activities in November 2009 (demonstrating compliance beginning in November 2009), and
- 2) evidence or records sufficient to demonstrate that the registered entity's prior maintenance and testing activity occurred in or after November 2003 (to show compliance between June 18, 2007 and November 2009).

Example 2

In this example, the registered entity has its first audit on April 10, 2010. It has a documented maintenance and testing interval of six years, it is due to conduct maintenance and testing in November 2012, and it has not conducted maintenance and testing on its equipment since the June 18, 2007 mandatory and enforceable date for the standard.

- 1) The CEA is to obtain evidence of the registered entity's maintenance and testing activities in November 2006 (demonstrating compliance beginning on June 18, 2007).
- 2) In this situation the CEA would not require evidence of the registered entity's November 2000 maintenance and testing.
- 3) During the next audit, the CEA would require evidence of the registered entity's November 2012 maintenance and testing.

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This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
April 19, 2011	Posted Final CAN	
November 11, 2011	Posted Revised CAN	Revised target audience to CEAs
February 24, 2012	High-Level Review Received	
March 9, 2012	Remanded to NERC staff for further work	

CAN Prioritization Form

Industry Suggestions for Order of Priority

Please complete the CAN Prioritization Form and email it to cancomments@nerc.net.

Contact Information

Name:

Phone Number:

Email Address:

Entity Represented:

Region:

Please rank the criticality of potential CANs from the list located on the NERC Compliance Application Notice Web site, "CAN Status" spreadsheet: <http://www.nerc.com/files/CANs%20Status.pdf>.

CAN Number

Standard

Importance Level (High, Medium or Low)

If desired, provide rationale for your ranking:

Optional Information:

Provide any input to be considered in the development of this Compliance Application Notice:

CAN Number (If a CAN has been numbered, it is under development)	CAN Requestor	Status	Standard	Topic of CAN	Item Description/Driver for Request (NERC has tried to identify these issues without identifying regions or registered entities; the description is a summary at the time of quarterly prioritization. It may not include all the related information currently identified with each possible CAN; NERC will document other information related to each within that CANs development history. Items listed here may require more than one CAN per standard or a group of similar issues into one CAN, depending on efficiencies, other NERC-wide efforts, etc.)
CANs in Development or Final					
5		Final	CIP-002 R3	Critical Cyber Asset Designation for System Operator Laptops	Registered entities and Regional Entities requested clarity regarding whether system operator laptops with the capability and purpose of controlling Bulk Electric System assets remotely (whether in normal operations or in emergencies) should be designated as Critical Cyber Assets (CCAs).
6		Final	EOP-005 R7	Verification of Restoration Procedure	This CAN provides instruction for assessing whether: 1) an entity has verified its restoration procedure “by actual testing or by simulation,” as required by EOP-005 R7, and 2) the use of a third-party vendor impacts a registered entity’s obligation under the standard
7		Final	CIP-004 R4.2	Revocation of Access (physical and electronic) to CCAs	Registered entities and Regional entities requested clarity about the extent and timing of revocation of access to Critical Cyber Assets (CCAs) required in CIP-004 R4.2. Specifically, clarity was sought on what constitutes revocation and access (physical and electronic), to CCAs under different entity-specific scenarios.
8		Final	PRC-005 R2	Basis for First Maintenance and Testing Date	NERC Compliance received a request for clarification on PRC-005 R2 regarding the monitored timeframes for gathering evidence pre-June 2007 when determining compliance with an entity's maintenance and testing program. What is the validity of a Regional auditor to ask for evidence pre-June 2007 even though there was no obligation to retain records until at least June 17, 2007?
9		Final	FAC-008 R1 FAC-009 R1, R2	Facility Ratings and Design Specifications	This CAN provides instruction for assessing compliance with FAC-008 R1 and FAC-009 R1 when an entity’s constructed Facilities do not match its design specifications.
10		Final	Multiple	Implementation of "Annual" in NERC Reliability Standard Requirements	This CAN discusses the implementation of annual requirements when the term "annual" is not defined by the standard.
11		Final	PRC-005 R2	Interval Start Date for New Equipment	NERC Compliance received a request for clarification on PRC-005 R2 regarding gathering evidence of initial testing for new equipment
12		Final	Requirement of periodic action by Effective Date	Completion of Periodic Activity Requirements During Implementation Plan	Registered entities and Regional entities have requested that NERC provide clarification on whether a registered entity must provide evidence that it completed a periodic action or event required by a NERC Reliability Standard prior to the registered entity’s Effective Date for the standard.
13		Final	PRC-023 R1 and R2	Effective Dates for Switch-On-To-Fault Schemes	This CAN clarifies the Effective Dates for SOTF schemes included on 1) transmission lines operated at 200 kV and above, and 2) transformers with low voltage terminals connected at 200 kV and above, under PRC-023 R1 and R2.
15		Final	EOP-002 Attachment 1; EOP-005 R11.3; IRO-002 R4, R5, R6; IRO-003 R1, R2; IRO-005 R1; and IRO-006.4.1 R1.4.1	Unavailability of NERC Software Tools	NERC Compliance received a request for clarification on a suite of reliability standards that require the use of a NERC tool. What is a registered entity's performance obligation to a standard's requirements when a NERC Tool is unavailable?
17		Final	CIP-007 R5	Technical and Procedural System Access and Password Controls	Is a CEA to verify that technical controls, procedural controls, or both are implemented in assessing compliance with CIP-007 R5?
18		Final	FAC-008 R1.2.1	Terminal Equipment	This CAN provides instruction for assessing what equipment should be considered “terminal equipment” under FAC-008.
19		In Development	CIP-007 R3	Implementation of Software Security Patches	Is a registered entity required to have a technical control for password configuration or would a manual solution meet the requirement? How would a manual solution be audited? When and under what conditions is a TFE is required?
20		Final	TPL-002 R6 & R11 TPL-002 R1.3.12 TPL-003 R1.3.12 TPI-004	Equipment Outages	NERC received a request for clarification of whether maintenance outages, including Protection Systems, must be included in operational planning studies under TOP-002 or in transmission planning assessments under TPL-002, TPL-003, and TPL-004.

Last Updated:
4/10/12

22		Final	VAR-002 R1	Generator AVR Operation in Alternative Mode	NERC received requests for clarification regarding whether a generator may be operated in manual mode during start-up.
23		In Development	CIP-005 R3 CIP-006 R6 CIP-007 R6	Logging system failures	NERC received a request for clarification of whether any exception exists for an entity that cannot log access 100% of the time, 24 hours per day, seven days per week, and if not, whether the entity needs to file a self-report any time the access logging system fails.
24		Final	CIP-002 R3.1	Routable Protocols and Data Diode Devices	NERC received a request for clarification of whether the communication characteristics of data diode devices can be used to exclude non-critical Cyber Assets from consideration as CCAs when a routable protocol is implemented, thereby making them inapplicable to CIP standards.
26		Final	TOP-006 R3	Protective Relays	NERC received a request for clarification of whether an RC, TOP and BA, under TOP-006 R3, needs to provide appropriate technical information to its operating staff for all protective relays in its area whether or not it has the responsibility or ownership of the protective relays.
27		Final	TOP-003 R2	Coordination of Scheduled Outages	NERC received a request to clarify whether TOP-003 R2 requires the BA to plan and coordinate scheduled outages of generators within the BA's area.
28		Final	TOP-006 R1.2	Reporting Responsibilities	This CAN provides instruction for assessing whether a BA or TOP has fulfilled the requirements for reporting transmission or generation resources available for use to RCs and other affected BAs and TOPs under TOP-006 R1.2.
29		Final	PRC-004 R2 R3	Protection System Misoperations	NERC received a request for clarification regarding whether entities must develop and implement Corrective Action Plans (CAPs) for, and maintain a record of, all Misoperations or only those that must be reported to NERC/RAPA.
30		Final	Attestations	Attestations	NERC received a request for clarification regarding the appropriate situations and uses of attestations as evidence of compliance with a reliability standard.
31		Final	CIP-005 CIP-006 CIP-006 R1.1	Acceptable Opening Dimensions	NERC received a request to define the entry point metric definition of the access points on the perimeter. NERC also received a request for clarification for an acceptable entry point into a Physical Security Perimeter (PSP) of CCAs, as well as acceptable opening dimensions.
33		In Development	PRC-023 R1.8; • R1.9 • (R1.1; R1.6; R1.7)	Transmission Relay Loadability	NERC Compliance received a request for clarity on: load remote to system; generation remote to load; if there is a 4-hour load rating or can a seasonal facility rating be used for R1.1 Furthermore, in a Directional Comparison Blocking (DCB) Scheme, does the reverse looking zone need to comply with PRC-023 loadability requirements?
34		In Development	EOP-002 R1 IRO-001 R3 TOP-001 R1	Use of Authority Letters	NERC received a request to clarify what criteria auditors consider when reviewing an authority letter.
35		In Development	Periodic Data Submittals	Periodic Data Submittal Violations	NERC received a request for clarification of whether violations would be mitigated if they were included in periodic data submittals.
37		In Development	Roll-up Violations	Roll-up Violations	NERC received a request for clarification regarding whether the finding of non-compliance of one requirement would be applied across other standards to which that requirement applies
38		In Development	PER-002 R4	Training Hours	NERC received a request for clarification of how many training hours equals the required five days of training per PER-002 R4.
39		Final	DOE 417	Filing DOE Form OE-417 Event Reports	The Department of Energy's (DOE) new online process for submitting the OE-417 disturbance reporting form does not automatically issue a copy to NERC or the Regions.
40		Final	BAL-003 R2	Frequency Bias Calculation	NERC received a request for clarification on the proper approach to determine Frequency Bias Setting.
41		In Development	IRO-004 R1	Dynamic Modeling in a Next-Day Assessment	NERC received a request for clarification on whether complete dynamic modeling is required for next-day assessments.
42		In Development	PRC-001 R1 PRC-001 R2 PRC-001 R4	System Protection Coordination	NERC received a request to clarify the use of the term "Generator Operator" (Not GOP's responsibility in company to know protection system)
43		Final	PRC-005 R2	Protection System Maintenance and Testing Evidence	NERC received requests for clarification on what types of evidence are typically used to demonstrate compliance with Protection Systems maintenance and testing in certain compliance areas.
44		In Development	TOP-001 R1 TOP-001 R2 TOP-001 R5 TOP-001 R8	Operating Emergencies and Emergency Conditions	NERC received a request for clarification on the definition of emergency, operating emergency and system emergency as used in TOP-001. There are several references to the word emergency in TOP-001, but none of those references are capitalized to indicate a glossary term. TOP-001 R8: During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to

Not Yet Prioritized	Source	Status	Standard	Topic of CAN	Item Description/Driver for Request NERC has provided the below information for each potential CAN issue which, in most cases, is the extent of the information received with the request. If you would like to discuss any of the below, please contact one of NERC CAN team members or email the team at cancomments@nerc.net .
CAN Number Pending (awaiting prioritization)	Registered Entity	Not Yet Prioritized	COM-002 R1.1	Communication Paths and Directives	1. Does "predetermined communication paths" in R1.1 mean certain operators in the control room rather than facilities peoviding the communication paths? R1.1 states "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." 2. There currently appears to be a gap in this requirement for situations where an RC or BA dispatch generation under normal and emergency conditions, but the directive is given to a LSE which is not registered as a GOP. 3. What defines a directive and under what circumstances must a directive be used?
CAN Number Pending (awaiting prioritization)	Registered Entity	Not Yet Prioritized	EOP-005	Restoration Plan Coordination	1. Does a GO that does not participate in the blackstart process need to coordinate restoration plans? 2. Discussions arose regarding the applicability of this requirement as it relates to long term scheduled equipment outages. Should an entities restoration plan be reviewed and updated for long term scheduled equipment outages as these change the power system network?
CAN Number Pending (awaiting prioritization)	Registered Entity	Not Yet Prioritized	EOP-008 R1	Implementation Plan and Test Drills	1. Does the requirement to have a plan imply the implementation of that plan? 2. R1 states that a RC, TOP, and BA must have a plan to continue reliability operations in the event its control center becomesinoperable. R1.1 talks about the contingencst plans must be "viable and R1.5 talks abpout tests or drill "to ensure viability of the plan." Guidance is requested to clarify what is required to demonstrate the "viability" of a plan. Do test drills need to include the time-period covering the ramping of all generators? 3. Another issue is that manual mark down data is allowed to be sent to the NSP Backup Control Center prior to the link being cut from the primary source. Do test results confirm the viability of the backup plan? Should entities change the order of the steps regarding the Backup Control Center test drill to reflect the link being cut from the primary source prior to any manual data being sent to the backup facility. This change would remove the dependency.
CAN Number Pending (awaiting prioritization)	Registered Entity	Not Yet Prioritized	PRC-017 R1.1	Maintance and Testing Plans for SPS	R1.1 states that SPS identification shall include but is not limited to: relays, instrumnent transformers, communication systems, and batteries. Does a SPS to fall under the NERC definition of a Protection System? SPS includes control circuitry which would be included in the Protection System maintenance and testing plan. Guidance is requested to clarify what is expected to be addressed in the maintenance plan for a SPS.

						NERC COMMITTEE, REGIONAL ENTITY and REGISTERED ENTITY PRIORITIZATION RESULTS									
Prioritized CANs	Source	Status	Standard	Topic of CAN	Item Description/Driver for Request (NERC has tried to identify these issues without identifying regions or registered entities; the description is a summary at the time of quarterly prioritization. It may not include all the related information currently identified with each possible CAN; NERC will document other information related to each within that CANs development history. Items listed here may require more than one CAN per standard or a group of similar issues into one CAN, depending on efficiencies, other NERC-wide efforts, etc.)	Standards Committee (SC) Prioritization	Compliance and Certification Committee (CCC) Prioritization	Operating Committee (OC) Prioritization	Planning Committee (PC) Prioritization	Critical Infrastructure Protection Committee (CIPC) Prioritization	Regional Entity - SERC Prioritization	Regional Entity - FRCC Prioritization	Registered Entity - Dominion Prioritization	Registered Entity - IESO Prioritization	Registered Entity - APX Power Prioritization
HIGH	Registered Entity	Prioritized	CIP-002	CCA designation of management console for virtual machine (VM) technology	With the Management Console having the capabilities for impacting the CCA VM Client, the Management Console should be considered a CCA. With the expanded usage of Virtual Machine technology it is in the best interest of the industry to have this clearly outlined to make sure the overall reliability of the BES is maintained.	HIGH	N/A	HIGH	N/A	HIGH	HIGH	HIGH	HIGH	N/A	HIGH
HIGH	Region	Prioritized	CIP-007	Critical Asset losing its designation	If a Critical Asset loses its designation, as can be expected when the Bright Line criteria of CIP-002-4 changes the identification criteria for Critical Assets, when you lose the Critical Asset, you automatically lose the Critical Cyber Assets and the applicability of the CIP standards to any Cyber Assets previously protected at that no-longer-critical asset. In this instance, do you have to conform to CIP-007 R7?	HIGH	HIGH	HIGH	N/A	HIGH	LOW	HIGH	LOW	N/A	N/A
HIGH	Registered Entity	Prioritized	CIP-007	Whether USB-only printers are considered Cyber Assets	Is a USB-only printer a Cyber Asset, or is it only a peripheral device? The term "printer" also needs to be clarified for compliance purposes. What is considered peripheral and what is considered serial. The Glossary definition of a Cyber Asset is: "Programmable electronic devices and communication networks including hardware, software, and data."	HIGH	HIGH	HIGH	N/A	HIGH	HIGH	LOW	LOW	N/A	N/A
HIGH	CEAs/Registered Entity	Prioritized	COM-001 R1.1-R1.4	Telecommunication Redundancy	Is a single point of failure an automatic failure to comply with R1.1 - 1.3. If a facility is not sufficiently redundant, is an entity automatically out of compliance with all R1 sub requirements but only R1.4?	LOW	MEDIUM	LOW	N/A	N/A	HIGH	HIGH	MEDIUM	N/A	N/A
HIGH	Region/Registered Entity	Prioritized	EOP Standards	Evidence of communication capability, access and verification under the EOP Standards	NERC Compliance received a request for clarification regarding what evidence a CEA will verify to determine compliance in regard to communication, capability and access using NERC software tools. (RCIS, WECCnet)	HIGH	HIGH	HIGH	N/A	N/A	LOW	HIGH	LOW	LOW	N/A
HIGH	Registered Entity	Prioritized	FAC-003 R1	TVMP Changes	NERC received multiple requests for clarification on FAC-003-1 R1 regarding the allowable timeframe for implementation when an entity changes one TVMP plan based on normal trend to another TVMP plan based on clear cut. Once changed is the entity bound to implement immediately? Does the standard provide for entities to have a transition period while changing TVMP plans?	MEDIUM	HIGH	MEDIUM	MEDIUM	N/A	HIGH	HIGH	HIGH	N/A	N/A
HIGH	Registered Entity	Prioritized	FAC-003 R1.2.2 (and subrequirements R1.2.2.1 & R1.2.2.2)	IEEE Standard conflicting with NERC standard	According to R1.2.2., "Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003"... A newer version of this IEEE standard was published in 2009 which contains clearances that are less restrictive than the 2003 version. Would a Transmission Owner be found non-compliant if they adopt the 2009 version, even though the requirement specifically refers to the 2003 version?	MEDIUM	HIGH	MEDIUM	HIGH	N/A	LOW (if regulatory approval is expected in 2012) otherwise HIGH	HIGH	HIGH	N/A	N/A
HIGH	Registered Entity	Prioritized	Multiple	Definition of radial transmission	Source documents from multiple regions and from NERC demonstrate the inconsistent application of "radial."	LOW	HIGH	LOW	LOW	N/A	LOW	HIGH	LOW	LOW	N/A
HIGH	Registered Entity	Prioritized	Multiple	Define Calendar Year and other time periods	If a standard requires the performance of an activity every four calendar years, and an entity performed the activity on January 1, 2008, would the entity meet the standard if the entity performed the activity anytime during 2012? Or would the completion be required on December 31, 2011?	LOW	LOW	LOW	LOW	LOW	LOW	HIGH	LOW	HIGH	N/A
HIGH	Registered Entity	Prioritized	Multiple	Intpretation of BPS definition	Request for clarification on the difference between BPS and BES. The BES Definition SDT is currently working on this issue. Two recirculation ballots, one for the Definition of Bulk Electric System (BES) and associated implementation plan, and one for the application form titled 'Detailed Information to Support an	LOW	LOW	LOW	LOW	N/A	LOW	HIGH	MEDIUM	LOW	N/A
HIGH	NERC	Prioritized	PER-002	Consistency of evidence for operating personnel training	Clarification may be necessary to ensure that Registered Entities understand what types of operating personnel training is expected and to provide auditors with a consistent approach for determining compliance with PER-002. This issue may be resolved with PER-005 R3, which states: At least every 12 months each Reliability Coordinator, Balancing	HIGH	LOW	HIGH	N/A	N/A	LOW	MEDIUM	MEDIUM	HIGH	N/A
HIGH	NERC	Prioritized	PER-002 PER-003	Certification of Remote Operators	Which control center operators, remote or local or both, need to be NERC-certified system operators to be in compliance with PER-002 and PER-003? One position states that if an operator is performing (or sending an associated directive to field personnel to perform) an activity within one of the certified functions (being BA, TOP, or RC) the operator must be certified regardless of being remote.	HIGH	MEDIUM	HIGH	HIGH	N/A	HIGH	MEDIUM	MEDIUM	LOW	N/A
HIGH	Registered Entity	Prioritized	PRC-004	Consistent reporting of protection system Misoperations	Clarify the audit scope for Misoperations and CAPs to be reviewed. Request clarification as to whether non-reportable Misoperations are subject to compliance audits. Recommendation that an audit can cover any time and any action within the audit period regardless of reportability of misoperations. Also, does operation of a relay during an abnormal condition constitute a misoperation under PRC-004?	MEDIUM	LOW	MEDIUM	LOW	N/A	MEDIUM	HIGH	LOW	N/A	N/A
HIGH	Registered Entity	Prioritized	TOP-002 R2, R6, R8, R10, R11, R19	System Conditions	R6: What is the responsibility of the BA to plan to meet CPS and DCS under unscheduled changes in the system configuration and generation dispatch? R2, R8, and R19: Clarity on BA obligations; the request for clarity seems to try to change the standard.	HIGH	HIGH	HIGH	N/A	N/A	MEDIUM	LOW	MEDIUM	LOW	N/A
MEDIUM	Registered Entity	Prioritized	CIP-004 R3.1	Criminal background checks	Clarification regarding the use of criminal history checks conducted by the FBI in support of the Access Authorization process mandated by the US Nuclear Regulatory Commission. Many companies rely on this process to support their CIP Personnel Risk Assessments (PRA) conducted under the CIP-004 standard. We think a CAN addressing the acceptability of this practice would help provide clarity to the process.	MEDIUM	MEDIUM	MEDIUM	N/A	LOW	MEDIUM	LOW	MEDIUM	N/A	N/A
MEDIUM	Registered Entity	Prioritized	EOP-003 R3 & R5	Applicability of BA or TOP to automatic load shedding or manual load shedding	NERC Compliance received a request for clarity regarding the BA and TOP applicability with regard to compliance with the EOP-003. Also, does this apply only to automatic load shedding or does it also apply to manual load shedding?	LOW	MEDIUM	LOW	N/A	N/A	MEDIUM	MEDIUM	MEDIUM	MEDIUM	N/A
MEDIUM	Registered Entity	Prioritized	FAC-014 R5	Responsibility for SOLs and IROLs	Clarification is needed to demonstrate that each applicable function is responsible for establishing SOLs and IROLs regardless of whether the registered entity is included in the studies performed by an RC or PA. Expand CAN-000X (re: FAC-014 R2 and R4 on potential CAN list) or add an additional CAN.	LOW	MEDIUM	LOW	HIGH	N/A	LOW	MEDIUM	MEDIUM	N/A	N/A
MEDIUM	Registered Entity	Prioritized	IRO-005 R10	What does the term 'derived limits' mean in general and with regard to small generators?	The confusion with IRO-005-3a R10 is that it is not clear what the auditors would deem to be "derived limits" and what their approach would be to a small generator "...operating the Bulk Electric System." What is also not clear is how auditors would approach independent entities even becoming aware of derived limits.	MEDIUM	MEDIUM	MEDIUM	MEDIUM	N/A	LOW	LOW	LOW	LOW	N/A

MEDIUM	NERC	Prioritized	PRC-008 R1 PRC-011 PRC-017 R1.1	Does the term "Protection System" include UFLS and UVLS equipment? Also, is control circuitry considered part of an SPS and does that circuitry fall under the definition of a Protection System? What constitutes a Special Protections	Consider defining UFLS equipment as a Protection System or explicitly list what is included as part of UFLS equipment in order to remove confusion concerning this terminology. There is uncertainty as to what equipment is considered part of the Protection System, which has led to inconsistent applications to TOs and DPs with a UFLS Program. Clarify whether PRC-017 R1.1 specifically includes control circuitry as part of an SPS or if SPS falls under the definition of a Protection System.	MEDIUM	MEDIUM	MEDIUM	MEDIUM	N/A	MEDIUM	MEDIUM	LOW	N/A	N/A
MEDIUM	Registered Entity	Prioritized	TOP-002 R14, R16, R17	Intentional Time Delays notifying BA and RC	Define "Intentional Time Delay" as outlined in TOP-002 R14, R16 and R17. TOP-002 R14: Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:	MEDIUM	MEDIUM	MEDIUM	LOW	N/A	MEDIUM	MEDIUM	LOW	LOW	N/A
LOW	Registered Entity	Prioritized	CIP-003 R4 and R5	Protection and access control to CCA information	Clarify whether hashing is an acceptable method for information authentication in order to be in compliance with the requirements for authenticating secure messages.	HIGH	N/A	HIGH	N/A	LOW	LOW	MEDIUM	MEDIUM	N/A	N/A
LOW	Region	Prioritized	IRO-002 R3	Applicability of BA and TOP	Clarity requested from a region on the RC, BA, and TOP applicability. What must the BA and TOP do to comply with IRO-002 R3?	LOW	LOW	LOW	N/A	N/A	LOW	LOW	MEDIUM	LOW	N/A
LOW	Registered Entity	Prioritized	Multiple	Mapping of registered entity policies to NERC Standard Requirements	If an entity has one or more policies for any standard to demonstrate/define how it meets the requirements and sub-requirements how within the policy or policies the CEA is to verify each of the components laid out in the requirement and sub-requirements.	LOW	LOW	LOW	LOW	LOW	LOW	LOW	LOW	LOW	N/A
LOW	Registered Entity	Prioritized	TPL-002 R1.3.10 TPL-003 R1.3.10 TPL-004 R1.3.7	Power flow models and protection systems include relay devices as N-1	Clarification requested on whether the inclusion of redundant and backup protective system failures is required in power flow models.	MEDIUM	LOW	MEDIUM	LOW	N/A	LOW	MEDIUM	LOW	N/A	N/A
LOW	NERC/Region	Prioritized	TPL-003	Application of TPL-003 Table 1	Application of Table 1 in TPL-003 and proper modeling of contingency events (ie: Category C vs. D). Confusion about what is an extreme event and misunderstanding of categorizing simulations (found in Table 1 of the TPL standards) on the final outcome after the fault was cleared instead on the initiating event/fault as required.	LOW	LOW	LOW	LOW	N/A	LOW	LOW	LOW	N/A	N/A
LOW	Registered Entity	Prioritized	MOD-018 R1	Definition of "non-member entities"	Clarity regarding what is included as a "non-member" as found in MOD-018 R1. MOD-018 R1 states: The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of	LOW	MEDIUM	LOW	LOW	N/A	LOW	MEDIUM	LOW	N/A	N/A

CAN Number	Reasoning	Status	Issues that have been addressed		
14	Material covered in subsequent order	Addressed	IA & IC	IA & IC	Version 5 of the functional model refers to both IA and IC s interchangeably. Until all docs are fixed, they will be treated as the same.
21	CAN not appropriate vehicle but will hold for future	Addressed	COM-002	Definition of a Directive	NERC received a request for clarification of the definition of a “directive,” whether it applies to both non-emergency and emergency situations, and the required use of three-part communications.
25	CAN not appropriate vehicle but will hold for future	Addressed	EOP-001 R2.4	BA Restoration Plans	NERC received the following question: When a BA is not a registered TOP, how does it comply with EOP-001-0 R3.4 (U.S.) or EOP-001-1 R2.4 (Canada), which require BAs to have a set of plans for system restoration?
32	Issue too Broad	Addressed	EOP-008 TOP-002	Above and beyond security measures	NERC received a request for clarification regarding whether an entity will be considered non-compliant if the measures it has implemented to comply with the requirement(s) of a standard ~~1. meet the intent of the standard and~~ ~~2. exceed or are superior to the requirement of the standard~~
36	Bulletin is a better vehicle to answer	Addressed	PRC-023	Applicability	This CAN is in regard to PRC-023 and its applicability to Generator Owners that are not also transmission owners and/or distribution providers as stated in FERC Order 733.
N/A	Interpretation resolved issue	Addressed	BAL-001 R1 BAL-002	WECC Automatic Time Error Control Procedure	Clarification of whether the WECC Automatic Time Error Control Procedure (WATEC) violates BAL-001-0 R1. Also see Standard's list for clarification "which disturbances are excluded from compliance evaluation."
N/A	AML Corrected	Addressed	BAL-002 R1.1, R3, R3.1, R4, R4.2	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification. Need to compare standards VRF matrix (link: http://www.nerc.com/page.php?cid=2 20 285) with 2012 AML (link: http://www.nerc.com/files/2012%20AML%2010_19_11.xls) for consistency.
N/A	AML Corrected	Addressed	BAL-005 R1	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List
N/A	Issue too Broad	Addressed	CIP-002	CCAs	NERC Compliance received a request for clarification regarding different approaches to compliance and the scope of obligations on entities.
N/A	Covered by CAN-0012 and CAN-0010	Addressed	CIP-005 R4	Cyber Vulnerability Assessment	NERC Compliance received a request for clarification on whether or not it is appropriate to enforce this standard as requiring the entity to have performed a CVA prior to their Compliance Date.
N/A	AML Corrected	Addressed	COM-001 R6	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.
N/A	AML Corrected	Addressed	EOP-002 R7.2, R9	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.
N/A	Interpretation resolved issue	Addressed	FAC-003 MOD-013	Clarity, consistency of RRO standards and RRO requirements	NERC Compliance received a request for clarity regarding the proper use of RRO. Clarity on the RRO requirements and references in the currently approved NERC standards.
N/A	CAN not appropriate vehicle but will hold for future	Addressed	FAC-008	Submitted Example of Excellence	NERC Compliance received a request for a best practice example of how to approach facility ratings.

N/A	AML Corrected	Addressed	FAC-014 R2 and R4	Applicability	Inadvertent errors between stnds and compliance data sheets and database.
N/A	AML Corrected	Addressed	IRO-006 R3	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.
N/A	Not a CAN - either a Bulletin or Directive	Addressed	Multiple	New Generation Facility	Whether an entity must be registered before connection and any testing
N/A	Not a CAN - Registration issue	Addressed	Multiple	Entities that have smaller generator units within the larger facility	Registration issue
N/A	Not a CAN - Registration issue	Addressed	PRC-005	Commissioning Testing/Registration	When will an entity be subject to compliance? Clarify that an entity must be registered before connection and any testing.
N/A	Discussed in Bulletin 2011-002 Audit Notifications	Addressed	PRC-008 R2	Evidence	NERC Compliance received a request for clarification on audit notifications and "data requests" for this standard.
N/A	AML Corrected	Addressed	TOP-001 R7.1	Applicability	Inadvertent errors between stnds and compliance data sheets and database.
N/A	AML Corrected	Addressed	TOP-003 R1.2	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.
N/A	AML Corrected	Addressed	TOP-005 R2 and R3	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.
CAN Number	Reasoning	Status	Retired or Withdrawn CANs		
1	Material covered in subsequent order	Retired	INT-004 R1	Correction to VRF Matrix	This document provides notice of a correction in the Violation Risk Factor Matrix regarding compliance applicability of INT-004-2 R1.
2	Material covered in subsequent order	Retired	TOP-003 R1.3	Correction to VRF Matrix	This document provides notice of a correction in the Violation Risk Factor Matrix and the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of TOP-003-0 R1.3.
3	Material covered in subsequent order	Retired	IRO-006 R2	Correction to 2010 Actively Monitored Standards spreadsheet	This document provides notice of a correction in the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of IRO-006-4.1 R2.
4	Material covered in subsequent order	Retired	IRO-004 R3	Correction to VRF Matrix and Actively Monitored spreadsheet	This document provides notice of a correction in the Violation Risk Factor Matrix and the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of IRO-004-1 R3.
16	High-level review	Withdrawn	CIP-001 R1	Non-BES facilities	Is a registered entity required to include non-BES facilities in its Sabotage Reporting Procedure?

From: [Ben Engelby](#)
To: [Lee R. Pedowicz](#)
Subject: RE: NERC Announcement: Compliance Activity Regarding RSAWs and CANs
Date: Thursday, April 12, 2012 2:04:56 PM

Lee,

The changes to the CAN Process were posted for information only. However, we always welcome any suggested improvements to the process. If you have any comments, feel free to send them to me.

Thanks,
Ben

From: Lee R. Pedowicz [<mailto:lpedowicz@npcc.org>]
Sent: Thursday, April 12, 2012 1:33 PM
To: Ben Engelby
Subject: RE: NERC Announcement: Compliance Activity Regarding RSAWs and CANs

Good afternoon, Ben.

Thanks again for your help. One thing--regarding the CAN Process, those documents have just been posted for information, there are no comments being asked for?

Lee

From: Ben Engelby [<mailto:Ben.Engelby@nerc.net>]
Sent: Thursday, April 12, 2012 9:49 AM
To: Lee R. Pedowicz
Subject: NERC Announcement: Compliance Activity Regarding RSAWs and CANs
Importance: High

NERC Compliance Announcement

- RSAWS Posted for Industry Comments – Due April 30
- CANs Posted for Industry Comment and other CAN Activity – Due May 7

RSAWS Posted for Industry Comment

NERC is updating Reliability Standard Audit Worksheets (RSAWs) by integrating the standard drafting team's intent, obtaining broader industry input and resolving compliance monitoring approaches. The objective of obtaining this input is to reduce any gap between the drafting team's intent for the standard and compliance expectations. The intent of this effort is to consolidate compliance guidance documents into one location as much as possible, where Compliance Enforcement Authorities (CEAs) and registered entities can easily access relevant information.

NERC is also beginning to incorporate the Risk Based Compliance Monitoring Initiative concepts into the RSAWs with consideration of internal controls, including the purpose for internal controls and an opportunity for an entity to provide an auditor or CEA with its internal controls.

COM-002 RSAW posted for industry comment

- [Revised COM-002-2a RSAW](#)

The RSAW for COM-002 was developed in conjunction with the NERC Operating Committee (OC) and has been discussed with representatives from the NERC Compliance and Certification Committee (CCC). Submit **comments to RSAWfeedback@nerc.net by April 30, 2012.**

PER-005 RSAW posted for industry comment

- [Revised PER-005-1 RSAW](#)

There is one requirement for this standard that is currently enforceable, R3, and the remainder of the requirements will become enforceable over the next two years. This RSAW is being produced in response to industry requests for guidance prior to the remaining requirements becoming effective.

This RSAW was developed by the Personnel Subcommittee of the NERC OC in conjunction with the standard drafting team for this standard. It has been reviewed by the other NERC committees: The Standards Committee (SC), the Critical Infrastructure Protection Committee (CIPC), the Planning Committee (PC), the CCC and the OC. It is being provided for industry comment. Submit **comments to RSAWfeedback@nerc.net by April 30, 2012.**

CANs Posted for Industry Comment and other CAN Activity

CAN-0008 has been modified

- [CAN-0008 PRC-005 Basis for First Maintenance and Testing Date](#)

CAN-0008 was modified based on the direction in the NERC CEO's High Level Review and has been re-posted to the "Compliance Application Notices - Final" section of the CAN website.

No Action Required

CAN Priority Results and New Potential Issues for Prioritization has been posted

- [Priority List of CANs](#)

The CAN prioritization list has been updated to reflect the industry, NERC Committee and Regional Entity review of potential CAN issues. The rankings and final determination for each potential CAN as a high, medium or low priority issue are provided beginning on line 44 of the posted spreadsheet.

The spreadsheet contains new potential CAN issues that need to be prioritized, starting on

line 38. Entities are encouraged to submit recommendations for prioritization and comments or insight into each of the potential CAN issues.

Please submit your comments and prioritization of the new issues by submitting [CAN Process Appendix 2 – Industry Prioritization Form](#) to cancomments@nerc.net on or before **May 7, 2012**. The spreadsheet has been posted under the “Priority List of CANs” section of the CAN website.

Four CANs have been posted for industry comment

- [CAN-0019 CIP-007 R3.2 Implementation of Software Security Patches or Upgrades](#)
- [CAN-0023 CIP-005 R3 CIP-006 R6 Logging System Failures](#)
- [CAN-0034 EOP-002 R1 IRO-001 R2 and TOP-001 R1 Use of Authority Letters](#)
- [CAN-0038 PER-002 R4 Training Hours](#)

The above CANs were provided to the NERC committees – the OC, PC, CIPC, SC and CCC – for initial comments, however any committee comments reflected in the draft CANs may be not represent the opinion of the entire committee. These CANs are now being posted for industry comments under the “Draft CANs for Industry Review” section of the CAN website. Please complete the [CAN Process Appendix 3 – CAN Comment Form](#) and submit comments to cancomments@nerc.net on or before **May 7, 2012**.

Revised CAN Process Document has been posted

- [CAN Process \(redline\)](#)
- [CAN Process \(clean\)](#)

The CAN Process Document has been revised to reflect recent changes regarding CAN priority, the High Level Review, and the order and length of time for each comment period. Both a redline and clean version have been posted on the CAN website under “CAN Processes and Tools” section.

For more information regarding Compliance Application Notices, please contact [Valerie Agnew](#) at (404) 446-2566, [Ben Engelby](#) at (404) 446-2578 or [Caroline Clouse](#) at (404) 446-2588.

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NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Compliance Application Notice (CAN) Process

April 2012

RELIABILITY | ACCOUNTABILITY



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Introduction

Compliance Applications Notices (CANs) were created by NERC to fulfill ERO obligations under FERC Order 693¹ to provide compliance guidance to Compliance Enforcement Authority (CEA)² staff and to provide transparency to industry in regard to compliance monitoring³ with NERC Reliability Standards. CANs encourage accountability for both CEAs and registered entities, and were issued in response to requests for compliance guidance from industry stakeholders.

ERO Basis and Authority

NERC is the FERC-certified ERO and is accountable to the Commission and the industry for providing compliance guidance with regard to NERC Reliability Standards. The ERO's implementation of a thorough compliance program and appropriate enforcement actions, and providing continuing education and information campaigns to assist the industry sustain compliance, will enhance reliability of the Bulk Power System (BPS).

In FERC Order No. 693,⁴ several commenters argued that the standards were not comprehensive in nature and requested relief from monetary penalties and compliance with the NERC Reliability Standards. FERC responded, "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."⁵

Further, the Commission agreed with NERC that, even if some clarification of a particular NERC 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 NERC Reliability Standards.⁶

In addition, NERC and industry are accountable for the development of NERC Reliability Standards, as articulated in the 2005 Federal Power Act⁷ and FERC Order No. 672,⁸ which duly recognizes the requisite collective expertise, experience and judgment of all parties involved to develop and improve standards.

¹ FERC Order 693, Docket No. RM06-16-000.

² Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

³ The Three-Year ERO Performance Assessment stated that NERC should "evaluate and implement ways to make registered entities more aware of means currently available to them to obtain guidance on how to comply with reliability standards and how to demonstrate compliance." Appendix A – Progress in Implementing Specific NERC Actions from the Three-Year ERO Performance Assessment – March 16, 2011, p. 19.

⁴ FERC Order No. 693, Docket No. RM06-16-000.

⁵ *Id.* at Paragraph 274.

⁶ "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.

⁷ Section 215.d.2 located at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf.

Purpose

There are two significant and mutually reinforcing purposes of a CAN:

1. To establish consistency in the application of compliance criteria across all CEAs; and
2. To provide transparency to industry on how a CEA will apply compliance with a NERC Reliability Standard.

NERC received numerous industry comments requesting detailed compliance clarification of the NERC Reliability Standards. Below is a sampling of comments⁹ that NERC received during the comment periods of the NERC Three-Year Assessment¹⁰ and the NOPR of FERC Order No. 693. This feedback from industry factored significantly in the decision for NERC to implement CANs.

- NERC “need[s] to provide more information and guidance to registered entities concerning the compliance and enforcement process. This includes providing guidance on what it takes to comply with and demonstrate compliance with Reliability Standards, eliminating the backlog of audit reports and enforcement violations so that more precedents are available to industry, and providing more uniformity and consistency in audits between Regional Entities and different audit teams.”¹¹
- “A clear communication channel is fundamental to the success of the ERO. Connecting the feedback from different program areas, such as compliance monitoring and enforcement, reliability assessments and event analysis will prove valuable.”¹²
- “Without a designated communication process, the most efficient and effective compliance process is not in place between compliance staff and registered entities. Currently, each company and Regional Entity struggles with this problem on an inefficient, case-by-case basis. Hence, the [CAN] process NERC is recommending will increase efficiency and use less resources.”¹³
- “Some commenters argue that certain Reliability Standards require additional specificity or else users, owners and operators will not understand the consequences of a violation.”¹⁴

NERC appreciates interaction from Industry during comment periods, and channels of communication remain open at all times if questions or concerns regarding a particular CAN arise.

⁸ See P. 324 located at http://www.nerc.com/files/final_rule_reliability_Order_672.pdf

⁹ Commenters included industry trade associations that represent over 70 percent of utility customers in North America.

¹⁰ NERC Three-Year Assessment, Docket No. RR09-7-000, July 20, 2009.

¹¹ *Id.*

¹² *Id.*

¹³ *Id.*

¹⁴ FERC Order No. 693, Docket No. RM06-16-000.

Scope

A CAN is not a formal interpretation or a NERC Reliability Standard. Further, a CAN cannot modify or change a NERC Reliability Standard. CANs instruct CEAs to assess compliance by using either a specific method, or, if there are multiple ways for a registered entity to meet the requirements of a standard, a range of acceptable compliance actions.

Concisely stated, a CAN is based on the following four principles:

- a. A CAN provides instructions to CEAs regarding the boundaries within which to assess compliance with effective standards and requirements
- b. A CAN cannot expand a standard
- c. A CAN cannot add new requirements
- d. A CAN applies to any facilities that affect the reliability of the BPS

The CAN process includes several crosschecks with other NERC programs and departments, including a review by NERC legal staff and the NERC Executive Approval Team.¹⁵ CANs provide timely compliance instruction to CEAs to ensure consistent application of the standards. In the event that CEA practices vary, the posted CAN establishes a benchmark that all CEAs must adopt. By making instructions to CEAs transparent to industry, CANs also include the benefit of informing registered entities what to expect during an audit.

CAN Process

The CAN process is designed to give CEAs instruction of specific compliance applications in an expeditious manner. NERC follows several steps when developing CANs, including identifying issues that need clarification, prioritizing the issues, researching and developing CANs, providing the Regional Entities and industry time to comment, and submitting CANs to the Commission for review before posting them on the NERC Web site as final.

A. Issue Identification

NERC receives CAN topics through a variety of avenues, such as:

¹⁵ Chief Executive Officer, Senior Vice President and General Counsel, Senior Vice President and Chief Reliability Officer, Vice President and Director of Standards, Vice President and Director of Reliability Assessments, Vice President and Chief Security Officer, Associate General Counsel (693), Assistant General Counsel (CIP), Director of Compliance Operations, Director of Events Analysis and Investigations, Director of Training, Director of Situation Awareness and Director of Compliance Enforcement.

-
1. Industry comments received from individual registered entities, trade associations, and large corporations that have entities in multiple Regional Entities;
 2. Regional Entities and issues they observe;
 3. NERC in various oversight activities in CMEP and standards development; and
 4. Other regulatory bodies at the National or Provincial level.

NERC tracks the category source¹⁶ of the CAN request and will include it on the CAN Status spreadsheet posted on the NERC Compliance Application Notices web page.

CAN issues may relate to specific standards and requirements, crosscutting issues that cover various standards and requirements, or compliance monitoring processes and procedures. NERC encourages any interested party to submit an issue by sending a completed [Appendix 1 – CAN Template](#) to cancomments@nerc.net.

B. Determination whether CAN is the Appropriate Vehicle

Once an issue is received by NERC, the issue is reviewed to determine whether a CAN is the appropriate vehicle to resolve the issue. In this relevance determination, several factors are analyzed, including the number of entities that may be affected, the impact to reliability of the BPS, whether there are questions regarding compliance monitoring, if there are perceived inconsistencies in audit practices among Regional Entities, and if there is a need for clarity among industry stakeholders. NERC considers all requests for clarification, but in order for a CAN to be drafted, the issue must apply to multiple entities, multiple issues, or broad issues that apply to many industry members.

If it is determined that a CAN is not the appropriate vehicle to resolve the issue, NERC will determine if there is another vehicle. For example, if the issue is a question regarding the mandatory and effective date of a revision to a standard, a bulletin/public notice may be a better vehicle.

C. Prioritization of CANs

After the CAN issues are reviewed and it has been determined that a CAN is the appropriate vehicle to address the issue, the CAN is listed on the CAN Priority List, posted on the NERC Web site¹⁷ and is assigned a priority level.

There are several components that determine the priority of a CAN:

- Factors surrounding the issue
- Input from NERC committees
- Input from Industry

¹⁶ A category would be a broad designation such as a registered entity, Regional Entity, Trade Association, etc. but would not identify the name of source.

¹⁷ The complete list of CAN issues and prioritization can be found on the NERC web site: <http://www.nerc.com/files/CANs%20Status.pdf>.

NERC will determine the priority of the CAN based on factors surrounding the issue, which may include the significance of the issue,¹⁸ its impact to reliability of the BPS, the number of violations that have occurred due to the issue and the number of registered entities that are affected.

Industry may provide input as to the prioritization of a CAN and any initial comments on the issue by submitting a completed [Appendix 2 – Industry Prioritization Recommendation Form](#) to the NERC cancomments@nerc.net. A CAN issue may be prioritized into groups of high, medium or low.

D. Development Process

After an issue is identified and a priority is assigned, NERC staff begins the CAN development process. Before any drafting is done, the CAN team researches the issue. The first step is a review of the NERC Reliability Standard in its entirety, including applicable FERC orders, approved standards interpretations, RSAWs, CARs, and other communications and guidance.

Then the CAN team obtains technical information from subject matter experts, standard drafting teams, CEAs and Regional Entities. The input from subject matter experts may include soliciting input from industry committees or individuals, as appropriate. This research is conducted to determine the level of consistency that exists in regards to the issue.

The CAN team then vets the CAN through each NERC department including compliance, standards, events analysis, RAPA, and CIP to gain consensus on the issue. When the research is concluded and a draft is complete, the CAN is presented to the NERC Executive Approval Team for the first level of approval.

~~The NERC Executives Approval Team~~ may decide to place a CAN on hold for various reasons, and ~~the CAN team~~ NERC staff will follow the direction of the ~~NERC Executives Approval Team~~ to either research and develop the issue further, submit the CAN to NERC legal for review, or to present a technical change to the NERC subject matter experts.

E. NERC Committee Comment Period

Following NERC approval, the draft CAN is sent to the NERC Committees for review. The following committees will receive each Draft CAN for a 4-week comment period: Compliance and Certification Committee (CCC), Standards Committee (SC), Operating Committee (OC), Planning Committee (PC) and Critical Infrastructure Protection Committee (CIPC). After the committees have provided their input for each CAN, the CANs will be posted for registered entities for comment.

~~E.F.~~ Industry Comment Period

¹⁸ One determination of significance of the issue is whether the issue is related to one of the NERC identified high risk factors for the reliability of the BPS: (1) Misoperations of relay protection and control systems; (2) Human errors by field personnel; (3) Ambiguous or incomplete voice communications; (4) Right-of-way maintenance; (5) Changing resource mix; (6) Integration of new technologies; (7) Preparedness for high-impact, low frequency events; and (8) Non-traditional threats via cyber-security vulnerabilities.

The industry period lasts 21 days, and extensions of time may be granted upon request. Registered entities or their representatives may submit comments via Appendix 3 - the CAN Comment Form. In order to keep the CAN process transparent, NERC posts industry comments on the NERC Web site.

After the comment period, NERC staff analyzes all comments received and reviews the CAN for potential changes to make based on the comments. NERC will provide rationale for any changes made or not made to the CAN and will post the rationale on the NERC Web site.

Industry comments are especially important when the compliance application varies, as the CAN will establish a consistent application. Industry, in this context, includes registered entities, their trade associations or forums, and NERC stakeholder committees, as appropriate.

F.G. Regional Entity Comment Period

Following the industry comment period, NERC approval, the CAN is sent to the Regional Entities for verification of the compliance application. The Regional Entities, as a part of the ERO, have been involved throughout the development process. At this point, the Regional Entities are provided a period of five days two weeks to conduct a review of the drafted document and affirm consensus on the compliance application. ~~prior to posting. This provides the Regional Entities an opportunity to identify any issues or concerns that occurred in the editing of the draft that would prevent the CAN from moving forward in the process. In the event that a Regional Entity discovers content in the CAN that is technically incorrect or any other issue that should prevent the CAN from moving forward, the Regional Entity will notify NERC.~~

~~In the event that the Regional Entities support progression of the CAN, it will be posted on the NERC Web site for industry comment. The Regional Entities' may provide additional comments throughout the industry comment period.~~ Industry Comment Period

~~The industry period lasts 21 days, and extensions of time may be granted upon request. Registered entities or their representatives may submit comments via Appendix 3 - the CAN Comment Form. In order to keep the CAN process transparent, NERC posts industry comments on the NERC Web site.~~

~~After the comment period, NERC staff analyzes all comments received and reviews the CAN for potential changes to make based on the comments. NERC will provide rationale for any changes made or not made to the CAN and will post the rationale on the NERC Web site.~~

~~Industry comments are especially important when the compliance application varies, as the CAN will establish a consistent application. Industry, in this context, includes registered entities, their trade associations or forums, and NERC stakeholder committees, as appropriate.~~

G.H. Final Review and Posting

The final draft of the CAN is presented for NERC Executives to the CAN Executive Approval Team for a second review of the CAN, including any modifications that were made, or were not made, after

industry comments. Upon approval by the CAN Executive Approval Team, the CAN is sent to FERC staff and Canadian Regulators¹⁹ for review, after which it is posted as final on the NERC web site.

Once the CAN is posted, an email announcement is sent to all registered entities and CEAs.

H.I. Webinars and Training

NERC conducts webinars after CANs are posted as final on the NERC Web site to provide opportunities for questions from industry and CEAs. The webinar slides are posted on the NERC Web site.

NERC also provides training for CEAs and industry to develop awareness of the CANs and consistency in the use of the compliance application. Recent CANs and the CAN process are presented at trade forums, compliance workshops and committee meetings.

H.J. Expiration, [Withdrawal](#) or Removal of CANs

CANs are retired when a revised standard or interpretation that addresses the compliance application issue in the CAN is approved by FERC and is enforceable. Further, a CAN may be revoked or revised if a [Higher Level of Review](#) directs the CAN to be withdrawn or modified, or additional [technical](#) information is brought forward to demonstrate that the CAN is incorrect.

Benefits of CANs

The advantages of issuing a CAN are significant. CEAs receive instruction so compliance monitoring of the NERC Reliability Standards is conducted consistently. The result of the transparent process provides registered entities with visibility into how compliance will be applied. Additionally, CANs are generated in a relatively short time period compared to a much lengthier formal process.

A. [Provide Formal Feedback to Standards](#)

For each CAN that is drafted, NERC staff submits the issues raised during the development process to the Standards Development Teams and the standards issue database to be considered in ongoing or future standards projects, revisions to existing standards, or the initiation of new standards.

B. [Time to Develop](#)

The timeline for CAN development from issue identification to final posting is measured in terms of [months; typically 3 – 6 months](#). This process is designed to be much more responsive than either the formal Standards Interpretation Process or the Standards Development Process,²⁰ which may take 18 - 36 months, plus FERC approval time.

¹⁹ As requested by each Province.

²⁰ See the NERC Rules of Procedure, Appendix 3A, Standards Process Manual, Effective September 3, 2010.

CAN Issues and Concerns

During the development of the CAN process, NERC received issues and concerns from industry stakeholders. This section will highlight some concerns and provide answers to the questions received.

- *NERC received comments that CANs are overreaching the standards.* CANs give the necessary instruction to CEAs in order to monitor compliance to the standards in a consistent manner. CANs are temporary in nature and will be retired when a standard or interpretation that addresses the issues therein becomes effective.
- *NERC received comments that the CAN process is circumventing the standards process.* The CAN process and the standards process serve different purposes. The Standards Development Process is a codified process that creates regulation. The CAN process provides instruction on how CEAs are to assess compliance with that regulation. NERC must balance the long-term standards development process with the day-to-day compliance monitoring and enforcement responsibilities as the FERC-certified ERO.

~~Contesting a CAN~~ High Level Review

NERC's belief is that transparent, open communication of compliance applications provides an opportunity to formally address areas of concern. When industry takes issue with an application identified in a CAN, there are several existing processes available for formal resolution. In accordance with the NERC Rules of Procedure, a registered entity may contest a violation that was assessed due to the application of a CAN.

A registered entity or its representatives (requestor) may (in order of hierarchy):

1. Submit technical evidence in support of a request to NERC to have a CAN changed or removed.
 - a. If NERC does not respond to the request within a reasonable time as determined by the requestor, or if the requestor is not satisfied with the change to the CAN based on NERC's review of the technical evidence provided, then a requestor may:
2. Propose a change to the standard through a request for a formal interpretation²¹ or a Standard Authorization Request (SAR); or
3. Request a ~~Higher Level~~ High Level Review of the CAN²²

²¹ A formal 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.

- a. The first level of review would be conducted by NERC's Chief Executive Officer.
- b. If a registered entity is not satisfied with the results of the first level of review, the registered entity may request a second level of review by NERC Board of Trustees Compliance Committee (BOTCC).

The ~~hHigher-level~~ Level review-Review of the CAN may result in three options for disposition: (1) affirm CAN as written, (2) make recommended changes to CAN or (3) withdraw CAN. If a CAN is modified or withdrawn, there will be an announcement to industry and to ERO Compliance Enforcement Authorities to clarify the change.

The ~~hHigher-level~~ Level review-Review will begin when the registered entity or its representative submits Appendix 5 – CAN Higher- Level Review Form to NERC. NERC's Chief Executive Officer will have 14 days to review the CAN and determine whether the CAN will be affirmed, modified or withdrawn.

If a registered entity or its representative decides to pursue the ~~higher-High Llevel of R~~ review to the Board of Trustees Compliance Committee (BOTCC), they must submit a second request for ~~hHigher-l~~ Level R review by completing additional information and re-submitting Appendix 5. The BOTCC will review the comments and the applicable CAN at the next available time during its monthly closed-closed BOTCC meeting and make a determination whether to uphold the NERC Chief Executive Officer's decision. The BOTCC will review the decision on a de novo basis, and its decision will be to either uphold the CAN, direct the CAN to be modified or to withdraw the CAN.

At any time through the ~~hHigher-l~~ Level R review process an entity or its representative may withdraw its request for review.

Summary

Compliance Application Notices fulfill NERC's obligation as the ERO to provide a consistent compliance monitoring program under FERC Order No. 693. CANs carry out the requests of industry for clarification and provide timely compliance guidance in a transparent manner. CANs not only assist CEAs in monitoring compliance, but the industry benefits from understanding what the issues are and how to prepare for an upcoming audit. The CAN process is evolving and changes have been made to the program based on feedback from industry stakeholders, Regional Entities, and the NERC Board of Trustees.

²² See Appendix 5 - CAN Higher- lLevel Review Form.

Version History

Version	Date	Action
0	May 2010	Initial Draft
1	December 10, 2010	Updated CAN Process
2	April 14, 2011	Updated CAN Process with detailed steps
3	July 8, 2011	Updated CAN Process to include specific industry requests
4	August 15, 2011	Updated Purpose Section, Contesting a CAN Section, based on Board of Trustee recommendations.
5	October 2011	Updated CAN Prioritization Process, Regional Entity comment section, industry comment section, CAN higher-level review section, and added Appendices 1-5.
<u>6</u>	<u>April 2012</u>	<u>Updated the CAN Prioritization, committee and industry comment periods and High Level Review.</u>

From: [Guy V. Zito](#)
To: [Lee R. Pedowicz](#)
Subject: FW: CAN Process
Date: Friday, March 16, 2012 7:25:46 AM
Importance: High

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: Valerie Agnew [mailto:Valerie.Agnew@nerc.net]
Sent: Thursday, March 15, 2012 6:55 PM
To: Guy V. Zito; Walter Cintron
Subject: CAN Process
Importance: High

Hi Guy – I left you a voice message, too.

Re: The CAN Process – It is evolving. Initially it was 3-5 days just to give Regions an opportunity to raise a red flag if something should not be posted for industry comment, and then the Regions' comment period extended through the industry comment period.

SPPRE requested that we provide a longer time for the Regions to comment and they wanted to know if we could provide a site where the Regions could see each other's comments. We are instituting the 14 days and we're trying to find a technology solution for the second part of the request.

Re: None this year – Walt, you haven't seen any because there haven't been any thus far this year. We sent out 26 CANs for prioritization and pre-development comments. This request was sent to the NERC Committees, the ECEMG, the CMPWG and the CCWG in December. The due date was the end of February, but some groups needed more time, so we are still taking input. If you didn't see that request but want to see that request, let me know and I'll forward it. There are 8 CANs that we are finishing up from last year. Four are at the NERC Committees (a new step just for these 8 CANs) and will be sent to the Regions next.

Re: Who do notifications go to – for the Regions' review, the notifications will go to the ECEMG, the CMPWG and the CCWG. All other announcements will go to the canonly list. I think Walt is on the ECEMG. Guy, I don't know if you are...let me know if you want me to add you to a list.

We had been getting input back from NPCC from Lee and the NPCC registered entity group. However, what we are looking for is what the NPCC auditors and enforcement staff's

positions/compliance applications are.

Thanks – call me if you'd like to discuss –

Val

Valerie Agnew

*Manager of Compliance Standards Interface and Outreach
North American Electric Reliability Corporation (NERC)*

3353 Peachtree Rd NE

6th Floor, North Tower

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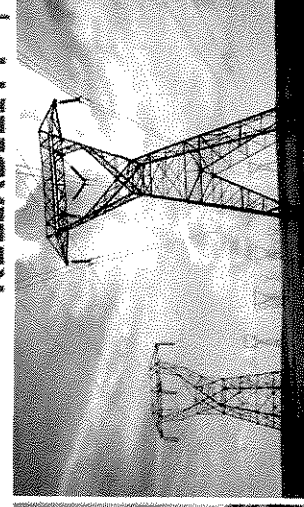


Reliability Standards Audit Worksheets (RSAWs)

Standards and Compliance Workshop
Ben Engelby, Senior Compliance Specialist

April 17, 2012

RELIABILITY | ACCOUNTABILITY



- Purpose of Enhanced RSAWs
- Categories of Standards for Consideration
- RSAW Options
- Industry Involvement

- To enhance RSAWs and to consolidate compliance guidance so both registered entities and Compliance Enforcement Authorities (CEAs) can access all relevant information in a single document while preparing for an audit.

- Continued effort for consolidation of all relevant info
 - Standard Drafting Teams' intent
 - Audit approach
 - Internal controls
 - NERC compliance guidance
- Involvement of Subject Matter Experts in development
- Increased transparency to industry

- Category 1: Future Standards
 - RSAW development in conjunction with a new standard project
- Category 2: Revising Standards
 - Regulatory approval, not yet enforceable
 - NERC Board approved, awaiting regulatory approval
 - NERC Board approved interpretation
- Category 3: Existing Standards
 - Consolidation of existing guidance documents

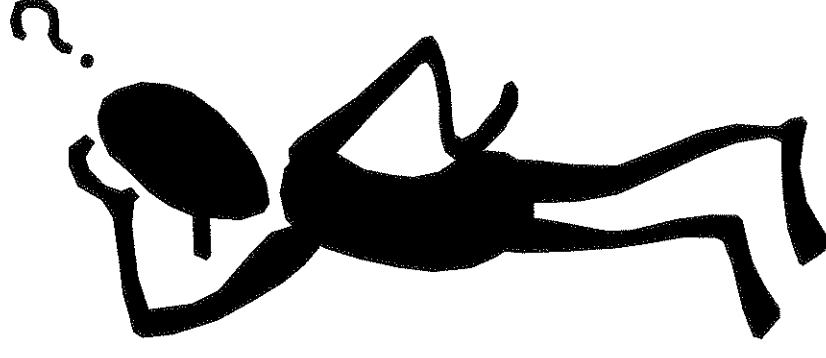
Four different alternatives to determine best approach:

- Option #1: RSAW development during a new Standard Drafting Team (SDT) Project
 - SDT works with NERC Compliance to develop RSAW
 - Process reviewed by Standards Committee
 - Sent to Trade Associations and Regions for input
- Option #2: PER-005
 - Initiated by Personnel Subcommittee (Operating Committee), then sent to SDT for development
 - NERC Standing Committees review
 - Industry comment period

Alternatives to determine best RSAW development approach:

- Option #3: FAC-003
 - Sent to Transmission Forum for input
- Option #4: COM-002
 - Sent to targeted NERC committees (Operating Committee and Compliance and Certification Committee) for feedback

- RSAW development process is still being determined
- NERC Compliance will continue to have ownership of RSAWs
- Based on the results from the test RSAWs, there may be one or more processes for development
 - Ensure vetting with appropriate industry members
- Expect more information regarding enhanced RSAWs in near future



Ben Engelby
Senior Compliance Specialist
(404) 446-2578
ben.engelby@nerc.net

From: [Guy V. Zito](#)
To: [rsc](#)
Subject: FW: NERC Announcement: Compliance Activity Regarding RSAWs and CANs
Date: Friday, April 13, 2012 7:49:19 PM

NERC is now posting RSAWs, should we be reviewing them? Let's discuss at the next meeting. CANs posted as well. See below.

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: Stacia-Ann Chambers [Stacia-Ann.Chambers@nerc.net]
Sent: Friday, April 13, 2012 10:36 AM
To: Stacia-Ann Chambers
Subject: NERC Announcement: Compliance Activity Regarding RSAWs and CANs



NERC Compliance Announcement

- RSAWS Posted for Industry Comments – Due April 30
- CANs Posted for Industry Comment and other CAN Activity – Due May 7

RSAWS Posted for Industry Comment

NERC is updating Reliability Standard Audit Worksheets (RSAWs) by integrating the standard drafting team's intent, obtaining broader industry input and resolving compliance monitoring approaches. The objective of obtaining this input is to reduce any gap between the drafting team's intent for the standard and compliance expectations. The intent of this effort is to consolidate compliance guidance documents into one location as much as possible, where Compliance Enforcement Authorities (CEAs) and registered entities can easily access relevant information.

NERC is also beginning to incorporate the Risk Based Compliance Monitoring Initiative concepts into the RSAWs with consideration of internal controls, including the purpose for internal controls and an opportunity for an entity to provide an auditor or CEA with its internal controls.

COM-002 RSAW posted for industry comment

- [Revised COM-002-2a RSAW](#)

The RSAW for COM-002 was developed in conjunction with the NERC Operating Committee (OC) and has been discussed with representatives from the NERC Compliance and Certification Committee (CCC). Submit comments to RSAWfeedback@nerc.net by April 30, 2012.

PER-005 RSAW posted for industry comment

- [Revised PER-005-1 RSAW](#)

There is one requirement for this standard that is currently enforceable, R3, and the remainder of the requirements will become enforceable over the next two years. This RSAW is being produced in response to industry requests for guidance prior to the remaining requirements becoming effective.

This RSAW was developed by the Personnel Subcommittee of the NERC OC in conjunction with the standard drafting team for this standard. It has been reviewed by the other NERC committees: The Standards Committee (SC), the Critical Infrastructure Protection Committee (CIPC), the Planning Committee (PC), the CCC and the OC. It is being provided for industry comment. Submit comments to RSAWfeedback@nerc.net by April 30, 2012.

CANs Posted for Industry Comment and other CAN Activity

CAN-0008 has been modified

- [CAN-0008 PRC-005 Basis for First Maintenance and Testing Date](#)

CAN-0008 was modified based on the direction in the NERC CEO's High Level Review and has been re-posted to the "Compliance Application Notices - Final" section of the CAN website.

No Action Required

CAN Priority Results and New Potential Issues for Prioritization has been posted

- [Priority List of CANs](#)

The CAN prioritization list has been updated to reflect the industry, NERC Committee and Regional Entity review of potential CAN issues. The rankings and final determination for each potential CAN as a high, medium or low priority issue are provided beginning on line 44 of the posted spreadsheet.

The spreadsheet contains new potential CAN issues that need to be prioritized, starting on line 38. Entities are encouraged to submit recommendations for prioritization and comments or insight into each of the potential CAN issues.

Please submit your comments and prioritization of the new issues by submitting [CAN](#)

[Process Appendix 2 – Industry Prioritization Form](#) to cancomments@nerc.net on or before **May 7, 2012**. The spreadsheet has been posted under the “Priority List of CANs” section of the CAN website.

Four CANs have been posted for industry comment

- [CAN-0019 CIP-007 R3.2 Implementation of Software Security Patches or Upgrades](#)
- [CAN-0023 CIP-005 R3 CIP-006 R6 Logging System Failures](#)
- [CAN-0034 EOP-002 R1 IRO-001 R2 and TOP-001 R1 Use of Authority Letters](#)
- [CAN-0038 PER-002 R4 Training Hours](#)

The above CANs were provided to the NERC committees – the OC, PC, CIPC, SC and CCC – for initial comments, however any committee comments reflected in the draft CANs may be not represent the opinion of the entire committee. These CANs are now being posted for industry comments under the “Draft CANs for Industry Review” section of the CAN website. Please complete the [CAN Process Appendix 3 – CAN Comment Form](#) and submit comments to cancomments@nerc.net on or before **May 7, 2012**.

Revised CAN Process Document has been posted

- [CAN Process \(redline\)](#)
- [CAN Process \(clean\)](#)

The CAN Process Document has been revised to reflect recent changes regarding CAN priority, the High Level Review, and the order and length of time for each comment period. Both a redline and clean version have been posted on the CAN website under “CAN Processes and Tools” section.

For more information regarding Compliance Application Notices, please contact [Valerie Agnew](#) at (404) 446-2566, [Ben Engelby](#) at (404) 446-2578 or [Caroline Clouse](#) at (404) 446-2588.

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From: Phan.Si_Truc@hydro.qc.ca
To: Lee R. Pedowicz
Cc: clermont.sylvain@hydro.qc.ca
Subject: NERC Announcement: Compliance Activity Regarding RSAWs and CANs
Date: Friday, April 27, 2012 3:28:57 PM

Lee, These are HQ TransÉnergie comments to be integrated with NPCC for the next week discussion

Si-Truc PHAN, ing.
Normes de Fiabilité & Encadrements Contrôle de réseau / Reliability Standards & Operating Procedures
Dir. Contrôle des mouvements d'énergie
19e Tour Est, Complexe Desjardins, H5B 1H7
Hydro-Québec TransÉnergie
Tel:(514) 879-4100 # 3610

page 5, " pupose": This is the pupose of the draft for the COM-002-2 ! I think that the purpose of the PER-005 should be here instead.

page 7, "Review the evidence provided by the entity to verify it has the following", "the 2nd point, "A description of the systematic approach to training (SAT) process the entity uses to develop initial and continuing training": Do you mean that the training firm must provide documents showing **its method** for 1. needs analysis 2. choice of design 3. implementation 4. evaluation 5. annual plan 6. annual evaluation OR do you mean a description of the method used to provide all the requirements of the PER-005 ? If it`s the latter, this is redundant since all the requirement of the PER-005 are covered in this document.

On the same page, 4th bullet, "Evidence of implementation..." Do you mean "Roster, learning assessments, evaluation of the learning activity and for CBTs the learning contracts and piloting projects ? if so, it might be a good idea to put these as examples or as requirements.

page 8, R.1.1, "Supporting Evidence....", "Describe, in narrative form, how you meet compliance with this requirement and the **internal controls** that are implemented for theses compliance actions". Internal controls ? Like what, for example ? This applies to all the requirements. What kind of internal controls do they expect ? This is my job. I just do it. If it's not done, our company might be heavily fined by NERC !

page 13, "Review the evidence...." Would ILAs be evidence ? They already show the links between course objectives and content; all that needs to be done is add a space to make the links between the objectives and the operators' tasks.

The second bullet: has a typo error on the word "baesd" should be "based". Would you need the actual course material, which can be huge or would you need a spreadsheet showing links between tasks- objectives- content- evaluation ?

page 14, R 1.3:

Is this the right description here. It's exactly the same words as the R1.2 on page 12.
Same comment about Internal controls.

page 15, Does this mean that an operator gets the passing mark on a pre-test and therefore, does not have to do this training ? AND the 200 CEH/3 years ?

page 17, #2, add as examples, DIF survey results (that's what NPCC members agreed to use), 360 Reviews, analysis and recommandation reports.

page 19, please add a bullet, which would apply for new employees or employees learning new task: "The final training evaluation, approved by the supervisor and a trainer or coach (for example the final coaching evaluation).

page 24, R 3.1 and page 25, last bullet ".....technology that replicates the operational behavior...." do you mean that it would replicate electronically the impacts of each action on the real network ?

Jones, Michael W. (US-WAL-Compliance)

From: Jones, Michael W. (US-WAL-Compliance)
Sent: Friday, April 27, 2012 11:15 AM
To: 'RSAWfeedback@nerc.net'
Subject: Comments Regarding COM-002 and PER-005 RSAWs Posted for Industry Comment

In response to NERC's request for comments regarding draft Reliability Standard Audit Worksheets COM-002 and PER-005, National Grid submits the following comments:

By asking auditors to evaluate internal controls for every standard, there is a risk that auditors will consider failures of internal controls to be violations of the standards even when entities have complied with the requirements of the standard. While the description in the draft RSAWs of how internal controls will be evaluated states that this evaluation is not part of the compliance/non-compliance determination, in practice during and audit, it may be difficult for an auditor to make that distinction. National Grid suggests that the internal control evaluation be removed from RSAWs and that RSAWs focus exclusively on measuring compliance with the actual requirements of the standard. The entity evaluation that is under development, and not the RSAWs for each and every standard, should serve the function of guiding auditors regarding the scope of audit that is required for a specific registered entity based on the entity's overall reliability risk. Making a risk-based evaluation of internal controls standard by standard is burdensome and repetitive of the function the entity assessment is intended to perform. This would not prevent a registered entity from reviewing internal controls with auditors when necessary to clarify and better demonstrate or clarify compliance, but the requirement to show internal controls need not be an express item in the RSAW. This is in line with the way audits have been conducted to date, entities often review internal controls with auditors in practice, but adding them to RSAWs makes this process appear to be required and could cause confusion.

In the alternative, if the internal control assessment remains in the RSAWs,

National Grid recommends that internal control questions should always be separate questions from questions that test compliance with the actual requirements. It needs to be clear that internal control questions are not part of the compliance / non-compliance determination.

For Example:

Question 1. Describe, in narrative form, how you meet compliance with this requirement.

Question 2. Describe, in narrative form, the internal controls that are implemented for this requirement.

The question should not be worded: Describe how you meet compliance and your internal controls.

Compliance enforcement authorities should always use the plain language of the standard for the compliance / non-compliance determination. RSAW's should never expand upon the plain language of standards / requirements.

Respectfully submitted,

Michael Jones
Reliability Compliance
National Grid
40 Sylvan Road
Waltham, MA 02451

T: 781-907-2404
michael.jones@us.ngrid.com

From: [Jordan Mallory](#)
To: [canonly](#)
Subject: NERC Announcement: Comment Period Extended for CIP CANs
Date: Friday, April 20, 2012 4:01:40 PM
Importance: High

NERC Compliance Announcement

Industry Comment Period has been Extended for CIP CANs

- [CAN-0019 CIP-007 R3 Implementation of Software Security Patches or Upgrades](#)
- [CAN-0023 CIP-005 R3 CIP-006 R6 Logging System Failures](#)

Due to the high importance of CIP version 5, the two CIP CANs that are currently posted for industry comment have been extended for two weeks following the CIP version 5 deadline. Please complete the [CAN Comment Form](#) and submit comments to cancomments@nerc.net on or before **June 4, 2012**.

For more information regarding Compliance Application Notices, please contact [Ben Engelby](#) at (404) 446-2578.

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Y

CAN Comment Form

Compliance Application Notice – 0019

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name:

Phone Number:

Email Address:

Entity Represented:

Region:

Primary Interest Groups

Are you suggesting a change to the groups mentioned? No

If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? Yes

If yes, explain what change and why:

General Comments:

CAN-0019 is attempting to expand the reliability standard by adding new requirements. The NERC CAN Process scope explicitly states that a CAN cannot expand a standard and a CAN cannot add new requirements.

We agree with the CCC Summary Comments as listed in draft CAN-0019.

If a gap is perceived in a Reliability Standard, then it should be addressed through the Standards Development Process. This CAN, as written, is overreaching the standard and is circumventing the Standards Development Process.

If a CAN is perceived to be required for CIP-007 R3, then Compliance Enforcement Authorities should be provided with guidance to stay within the bounds of the plain language of the standard / requirement.

Background

Are you suggesting a change to the background statement of the CAN? No – Not Applicable.

If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? Yes

If yes, explain what change and why:

Please see General Comments above.

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? Yes

If yes, explain what change and why:

This CAN should be withdrawn.

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? Yes

If yes, explain what change and why:

Please see General Comments above.

Compliance Application Notice – 0019

CIP-007 R3.2 Implementation of Software Security Patches or Upgrades

Posted: Month XX, 2012

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Primary Interest Groups

Compliance Enforcement Authority (CEA)¹

NERC

Regional Entity

Reliability Coordinator (RC)

Balancing Authority (BA)

Interchange Authority (IA)

Transmission Service Provider (TSP)

Transmission Owner (TO)

Transmission Operator (TOP)

Generator Owner (GO)

Generator Operator (GOP)

Load Serving Entity (LSE)

Issue: What is the timeframe for Responsible Entities to implement a software security patch or upgrade, or to request a Technical Feasibility Exception (TFE)?

To assess compliance with CIP-007 R3, CAN-0019 provides guidance to CEAs regarding the verification of software security patches or upgrades, implementation of compensating measures and verification of TFEs where applicable.

Compliance Application

CIP-007 R3 provides:

R3. Security Patch Management — *The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-3 R6, shall establish, document and implement a security patch management program for tracking, evaluating, testing, and*

¹ Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

Comment [A1]: CCC Summary Comments:

- This CAN is meant to address an issue that was not addressed at all in the CIP-007 standard, which is a time frame for accomplishing R3.2.
- The CAN sets an arbitrary 30 day time from the date of assessment. In that 30 days the Entity must either implement the patch or file a TFE, and there is no technical justification for the 30 days.
- While the performance is measurable, the CAN requires the use of a TFE for security patches that are not implemented when the standard does not require a TFE. TFEs are not required when a security patch is not implemented. Only compensating measures are required.
- The requirement does not include the "where technically feasible" language that signals TFEs are required for technical infeasibility. The CAN will compel a TFE for every security patch that cannot be implemented. This does not seem practical.

installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).

- R3.1.** *The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within 30 calendar days of availability of the patches or upgrades.*
- 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 compensating measure(s) applied to mitigate risk exposure.*

The availability of a patch often results in a greater risk to the system, since malefactors can reverse engineer the patch to create an attack vector.

Therefore, under R3.1, CEAs are to verify that the Responsible Entity made a determination of applicability within 30 calendar days of the availability of the security patch or upgrade to assess applicability to any of its Cyber Assets within the Electronic Security Perimeter (ESP) and to determine any risk associated with the security patch or upgrade.

Under R3.2, CEAs are to verify that the Responsible Entity implemented the applicable security patch or upgrade, or if the entity submitted a TFE and implemented compensating measures. One reading of R3.2 of the standard could mean that the implementation of the software security patch/upgrade or compensating measures is to be conducted immediately following its determination of applicability. However, a more reasonable approach is to provide some period of time to implement the security patch/upgrade or implement compensating measures and submit a TFE.

Thus, CEAs are to verify that a Responsible Entity implemented a security patch or upgrade within 30 calendar days following its determination that the security patch or upgrade was applicable. If a Responsible Entity has not implemented an applicable patch within 30 calendar days following its determination that the security patch or upgrade was applicable, the CEA is to verify that the Responsible Entity had, within the 30 calendar days, applied for a TFE and implemented its compensating measures.²

Effective Period for CAN

This CAN is to be used by CEAs for assessing compliance from the date the CAN is posted as final on the NERC Web site, regardless of the start date of any non-compliance or Possible Violation. CEAs are to use professional judgment, including consideration of the specific facts and circumstances of the non-compliance, to determine whether this application should be applied for registered entities that have been notified of an audit or are in the process of transitioning to compliance activities consistent with this CAN. This version of the CAN supersedes all prior communications and will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard

² CIP-007 R3 is subject to the TFE process pursuant to FERC order 130 FERC ¶ 61,050, Docket No. RR10-1-000, Issued January 21, 2010.

or interpretation becomes effective and addresses the specific issue contained in this CAN, a FERC order provides direction for an alternative compliance assessment, or a future High Level Review remands the CAN for modification or withdrawal.

Evidence of Compliance

A CEA is to obtain reasonable assurance of the entity's compliance by reviewing:

- evidence for the date the security patch or upgrade at issue became available to the Responsible Entity;
- evidence demonstrating that the registered entity evaluated all security patches and security upgrades within 30 calendar days of becoming available and made a determination whether they applied to Cyber Assets within the ESP and all access points to the perimeter; and
- documentation of the results of its evaluations and determination for all security patches and security upgrades.

If the registered entity determined that a security patch or upgrade was inapplicable, the CEA will not need to verify the below evidence.

When the security patch or upgrade is applicable, a CEA is to verify the evidence listed above and the following additional evidence. CEAs are to verify the implementation date for **either**

- the security patch or upgrade, or
- compensating measures.

This date should be reflective of the determined risk, but no later than 30 calendar days following the Responsible Entity's determination of applicability. If the Responsible Entity implemented compensating measures, a CEA is to verify that a TFE has been filed and those measures will be evaluated according to the TFE program.

When a security patch or upgrade is applicable but cannot be implemented, a CEA is to verify the approved TFE. In addition, the CEA is to verify that the implementation of compensating measures identified in the TFE was put into effect no later than 30 calendar days following its determination of applicability.

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From: [Jordan Mallory](#)
To: [canonly](#)
Subject: NERC Announcement: Comment Period Extended for CIP CANs
Date: Friday, April 20, 2012 4:01:40 PM
Importance: High

NERC Compliance Announcement

Industry Comment Period has been Extended for CIP CANs

- [CAN-0019 CIP-007 R3 Implementation of Software Security Patches or Upgrades](#)
- [CAN-0023 CIP-005 R3 CIP-006 R6 Logging System Failures](#)

Due to the high importance of CIP version 5, the two CIP CANs that are currently posted for industry comment have been extended for two weeks following the CIP version 5 deadline. Please complete the [CAN Comment Form](#) and submit comments to cancomments@nerc.net on or before **June 4, 2012**.

For more information regarding Compliance Application Notices, please contact [Ben Engelby](#) at (404) 446-2578.

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Y

CAN Comment Form

Compliance Application Notice – 0023

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name:

Phone Number:

Email Address:

Entity Represented:

Region:

Primary Interest Groups

Are you suggesting a change to the groups mentioned? Yes

If yes, explain what change and why:

The CAN does not include all the NERC entities that may be impacted by CIP-005 R3 and CIP-006 R6.

This is the same comment noted by the CCC.

Issue

Are you suggesting a change to the issue statement of the CAN? Yes

If yes, explain what change and why:

General Comments:

CAN-0023 is attempting to expand the reliability standard by adding new requirements. The NERC CAN Process scope explicitly states that a CAN cannot expand a standard and a CAN cannot add new requirements.

We agree with the CCC Summary Comments as listed in draft CAN-0023.

If a gap is perceived in a Reliability Standard, then it should be addressed through the Standards Development Process. This CAN, as written, is overreaching the standard and is circumventing the Standards Development Process.

If a CAN is perceived to be required for CIP-005 R3 and CIP-006 R6 then Compliance Enforcement Authorities should be provided with guidance to stay within the bounds of the plain language of the standard / requirement.

In addition, CAN-0023, as written, may dissuade registered entities from implementing computerized logging that is automated to avoid the additional 240 minute requirement and associated documentation burdens. If automated computerized logging is viewed as a good practice, this will dissuade its use.

Background

Are you suggesting a change to the background statement of the CAN? No – Not Applicable.
If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? Yes
If yes, explain what change and why:

Please see General Comments above.

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? Yes
If yes, explain what change and why:

This CAN should be withdrawn.

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? Yes
If yes, explain what change and why:

Please see General Comments above.

Compliance Application Notice – 0023

CIP-005 R3, CIP-006 R6 Logging System Failures

Posted: Month day, 2012

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Primary Interest Groups

Compliance Enforcement Authority (CEA)¹

NERC

Regional Entity (RE)

Reliability Coordinator (RC)

Transmission Operator (TOP)

Balancing Authority (BA)

Generator Operator (GOP)

Issue: How should a CEA verify that access was logged 24 hours per day, seven days per week?

For the purpose of aiding a CEA, this CAN provides instruction for how a CEA is to verify whether an entity maintained a log of access 24 hours per day and seven days per week.

Compliance Application

CIP-005 R3 provides, in pertinent part:

R3. Monitoring Electronic Access — *The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.*

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 each access point to the dial-up device, where technically feasible.*

Comment [A1]: CCC Summary Comments:

- The CAN expands the standard because the standard does not address logging system downtime.
- There is no technical justification of the selected time standards.
- There is no definition of unavailability, especially when there are needs for maintenance and other activities.
- By implementing patching activities addressed in a separate proposed CAN, there can be inadvertent violation of the timelines specified in this CAN.
- This CAN may have impacts on Service Level Agreements that were negotiated prior to this CAN.

Comment [A2]: CCC comment:

This CAN does not include all the NERC entities that may be impacted by CIP-005 R3 and CIP-006 R6.

¹ Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

R3.2. Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.

CIP-006 R6 provides, in pertinent part:

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 week**. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

- **Computerized Logging:** Electronic logs produced by the Responsible Entity's selected access control and monitoring method.
- **Video Recording:** Electronic capture of video images of sufficient quality to determine identity.
- **Manual Logging:** A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R4.

In order to allow for unforeseen events, maintenance and other activities, a CEA is to verify that the unavailability of an automated logging system is 240 minutes or less per calendar year, with no more than 15 minutes of continuous unavailability for a specific event, maintenance or other activity.

Effective Period for CAN

This CAN is to be used by CEAs for assessing compliance from the date the CAN is posted as final on the NERC Web site, regardless of the start date of any non-compliance or Possible Violation. CEAs are to use professional judgment, including consideration of the specific facts and circumstances of the non-compliance, to determine whether this application should be applied for registered entities that have been notified of an audit or are in the process of transitioning to compliance activities consistent with this CAN. This version of the CAN supersedes all prior communications and will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN, a FERC order provides direction for an alternative compliance assessment, or a future High Level Review remands the CAN for modification or withdrawal.

Comment [A3]: CCC comment:

No justification or rationale is provided with respect to 240 minute measure or the 15 minute measure. While these measures may seem like good ideas, they will cause problems for Registered Entities. Beyond doing the right thing, Entities would need to institute a tracking mechanism to facilitate assembling evidence that the arbitrary 240 minutes and 15 minutes per event timeframes were not exceeded. This appears to create two requirements that are not part of the standard.

Comment [A4]: CCC recommended addition

Comment [A5]: CCC recommended addition

Evidence of Compliance

CEAs are to verify evidence that registered entities' logging systems met access logging expectations as outlined above.

For more information please contact:

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Caroline Clouse
Compliance Specialist
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404-446-2588

CAN Comment Form

Compliance Application Notice – 0034

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name:

Phone Number:

Email Address:

Entity Represented:

Region:

Primary Interest Groups

Are you suggesting a change to the groups mentioned? Yes

If yes, explain what change and why:

The CAN should be limited to (CEA), NERC, Regional Entity, and the applicable functions in the standards being addressed. This is the same comment noted by the CCC.

Issue

Are you suggesting a change to the issue statement of the CAN? Yes

If yes, explain what change and why:

General Comments:

CAN-0034 is attempting to expand the reliability standard by adding new requirements. The NERC CAN Process scope explicitly states that a CAN cannot expand a standard and a CAN cannot add new requirements.

We agree with the CCC Summary Comments as listed in draft CAN-0034.

The standards do not require any specific format or contents of an authority letter. A CEA should be able to accept a range of styles and contents of an authority letter to meet compliance.

If a gap is perceived in a Reliability Standard, then it should be addressed through the Standards Development Process. This CAN, as written, is overreaching the standard and is circumventing the Standards Development Process.

If a CAN is perceived to be required for EOP-002 R1, IRO-001 R2, and TOP-001 R1, then Compliance Enforcement Authorities should be provided with guidance to stay within the bounds of the plain language of the standard / requirement.

Background

Are you suggesting a change to the background statement of the CAN? No – Not Applicable.

If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? Yes

If yes, explain what change and why:

Please see General Comments above.

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? Yes

If yes, explain what change and why:

This CAN should be withdrawn.

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? Yes

If yes, explain what change and why:

Please see General Comments above.

Compliance Application Notice – 0034

EOP-002 R1, IRO-001 R2 and TOP-001 R1 Use of Authority Letters

Posted: Month XX, 2012

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Primary Interest Groups

Compliance Enforcement Authority (CEA)¹

NERC

Regional Entity

Transmission Operator (TOP)

Balancing Authority (BA)

Generator Operator (GOP)

Distribution Provider (DP)

Load-Serving Entity (LSE)

Issue: What criteria do CEAs consider when reviewing an authority letter?

CAN-0034 provides guidance to CEAs regarding what information to verify in an authority letter.

Compliance Application

EOP-002 provides, in pertinent part:

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.*

M1. *Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.*

¹ Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

Comment [A1]: CCC Summary Comments:

- It's curious that the CAN speaks to authority letters and not the other acceptable evidence outlined in the three measures.
- It would be helpful to know the driver of the need for this CAN. The requirements and the measures in the three standards are straightforward.
- The "primary interest groups" should be limited to NERC, Res and the applicable functions in the standards being addressed.
- The CAN expands on the standard because the "evidence of compliance" section includes the obligation to pre-define situations where the operator exercises authority. If the goal of the CAN was to include an expectation that authority letters include a "who does what" listing, we'd recommend removing this CAN from consideration.

IRO-001 provides, in pertinent part:

R2. *The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.*

M2. *Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, job descriptions, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that the Reliability Coordinator has the authority to act as described in Requirement 3.*

TOP-001 provides, in pertinent part:

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.*

M1. *Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.*

CEAs are to verify an authority letter contains the job title of the applicable real-time systems personnel being given the authority and states level of authority/responsibility granted to the position to make necessary reliability decisions.

Effective Period for CAN

This CAN is to be used by CEAs for assessing compliance from the date the CAN is posted as final on the NERC Web site, regardless of the start date of any non-compliance or Possible Violation. CEAs are to use professional judgment, including consideration of the specific facts and circumstances of the non-compliance, to determine whether this application should be applied for registered entities that have been notified of an audit or are in the process of transitioning to compliance activities consistent with this CAN. This version of the CAN supersedes all prior communications and will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN, a FERC order provides direction for an alternative compliance assessment, or a future High Level Review remands the CAN for modification or withdrawal.

Evidence of Compliance

If a registered entity uses an authority letter as evidence, a CEA is to verify that the letter includes the job titles of the real-time systems personnel being given authority who are actively monitoring and responsible for operations.

Furthermore, if there is more than one job title the CEA is to determine that the authority letter clearly delineates what authority is given to each job title.

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404-446-2588

CAN Comment Form

Compliance Application Notice – 0038

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name:

Phone Number:

Email Address:

Entity Represented:

Region:

Primary Interest Groups

Are you suggesting a change to the groups mentioned? No

If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? Yes

If yes, explain what change and why:

General Comments:

CAN-0038 is attempting to expand the reliability standard by adding new requirements. The NERC CAN Process scope explicitly states that a CAN cannot expand a standard and a CAN cannot add new requirements.

PER-002 R4 used the term “five days.” A CAN is not the correct mechanism for defining terms, such as five days = 32 hours of training.

PER-005 R3 became effective on April 1, 2011 and states:

“At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel.”

PER-005 R3 clearly states the requirement for “at least 32 hours.” This requirement should not be retroactively applied to PER-002 R4.

If a gap is perceived in a Reliability Standard, then it should be addressed through the Standards Development Process. This CAN, as written, is overreaching the standard and is circumventing the Standards Development Process.

If a CAN is perceived to be required for PER-002 R4 Training Hours, then Compliance Enforcement Authorities should be provided with guidance to stay within the bounds of the plain language of the standard / requirement.

Background

Are you suggesting a change to the background statement of the CAN? No – Not Applicable.
If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? Yes
If yes, explain what change and why:

Please see General Comments above.

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? Yes
If yes, explain what change and why:

This CAN should be withdrawn.

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? Yes
If yes, explain what change and why:

Please see General Comments above.

Compliance Application Notice – 0038

PER-002 R4 Training Hours

Posted: Month day, 2011

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Primary Interest Groups

Compliance Enforcement Authority (CEA)¹

NERC

Regional Entity

Balancing Authority (BA)

Transmission Operator (TOP)

Issue: How many hours equals five days of training per PER-002 R4?

For the purpose of aiding a CEA, this CAN provides direction on assessing how many training hours is equal to the required five days of training per PER-002 R4.

Compliance Application

PER-002 provides, in pertinent part:

***R4.** For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.*

PER-002 does not specify how many hours are considered to be in a training day. For the purpose of determining compliance with PER-002 for "five days" per year of training, a CEA is to verify that all operating personnel have completed 32 hours of training.

Effective Period for CAN

This CAN is to be used by CEAs for assessing compliance from the date the CAN is posted as final on the NERC Web site, regardless of the start date of any non-compliance or Possible Violation. CEAs are to

Comment [A1]: CCC Summary Comments:

- The 5-days of training and/or 32-hours is thought to be a closed issue. The 5 days of training having already been defined as 32 hours. In addition, PER-002 R4 is being identified for retirement in lieu of PER-005 R3 already active (as of April 1, 2011), changing the requirement to read "32 hours."
- It would be helpful to know the driver of the need for this CAN. The RSAW provided by NERC to the CEA is very clear.

¹ Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

use professional judgment, including consideration of the specific facts and circumstances of the non-compliance, to determine whether this application should be applied for registered entities that have been notified of an audit or are in the process of transitioning to compliance activities consistent with this CAN. This version of the CAN supersedes all prior communications and will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN, a FERC order provides direction for an alternative compliance assessment, or a future High Level Review remands the CAN for modification or withdrawal.

Evidence of Compliance

CEAs are to look for evidence demonstrating that operating personnel received 32 hours of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel, each year as required in PER-002 R4.

For more information please contact:

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CAN Comment Form

Compliance Application Notice – 00_ _

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name:

Phone Number:

Email Address:

Entity Represented:

Region:

Primary Interest Groups

Are you suggesting a change to the groups mentioned? Yes / No

If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? Yes / No

If yes, explain what change and why:

Background

Are you suggesting a change to the background statement of the CAN? Yes / No

If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? Yes / No

If yes, explain what change and why:

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? Yes / No

If yes, explain what change and why:

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? Yes / No

If yes, explain what change and why:

From: [Monica Benson](#)
To: monica.benson@nerc.net
Subject: NERC: Standards Bulletin - March 12-18, 2012
Date: Monday, March 12, 2012 9:21:42 AM

Standards Bulletin March 12-18, 2012

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STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- [Project 2009-26: Interpretation of CIP-004-1 by WECC](#) – Open March 14- 23, 2012 ([Successive Ballot](#))
- [Project 2011-INT-02: Interpretation of VAR-002 for Constellation](#) – Open March 14-23, 2012 ([Initial Ballot](#))
- [Interpretation 2010-INT-05: Interpretation of CIP-002-1 R3 for Duke Energy](#) – Open March 14-23, 2012 ([Initial Ballot](#))

Posted for Comment (comment periods close at 8 p.m. Eastern)

- [NERC Functional Model: Demand Response Functions and Entities](#) – Open February 13, 2012-March 14, 2012 ([Comment Form](#))

- [Project 2009-26: Interpretation of CIP-004-1 by WECC](#) – Open February 9, 2012 - March 23, 2012 ([Comment Form](#))
- [Interpretation 2010-INT-05: Interpretation of CIP-002-1 R3 for Duke Energy](#) – Open February 9, 2012 - March 23, 2012 ([Comment Form](#))
- [Project 2011-INT-02: Interpretation of VAR-002 for Constellation](#) – Open February 9, 2012 - March 23, 2012 ([Comment Form](#))
- [Project 2007-17: Protection System Maintenance and Testing](#) (PRC-005) – Open February 28, 2012 - March 28, 2012 ([Comment Form](#))
- [Project 2007-09: Generator Verification](#) (MOD-026-1 and PRC-024-1) – Open February 29, 2012-March 29, 2012 ([Comment Form](#))
- [Project 2010-07: Generator Requirements at the Transmission Interface](#) (FAC-003-X and FAC-003-3) – Open March 9 - April 9, 2012 ([Comment Form](#))
- [Project 2007-09: Generator Verification](#) (MOD-025-2, MOD-027-1, and PRC-019-1) – Open February 29, 2012 - April 16, 2012 ([Comment Form](#))
- [Project 2010-07: Generator Requirements at the Transmission Interface](#) (PRC-005-1.1a) – Open March 2, 2012 - April 16, 2012 ([Comment Form](#))

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

- [Project 2007-09: Generator Verification](#) (MOD-025-2, MOD-027-1, and PRC-019-1) – Open February 29 - March 29, 2012 ([Join](#))
- [Project 2010-07: Generator Requirements at the Transmission Interface](#) (PRC-005-1.1a) – Open March 2-31, 2012 ([Join](#))

Pending Ballots (ballot periods close at 8 p.m. Eastern)

- [Project 2007-17: Protection System Maintenance and Testing](#) (PRC-005) – Open March 19-28, 2012 ([Successive Ballot and Non-binding Poll](#))

- [Project 2007-09: Generator Verification](#) (MOD-026-1 and PRC-024-1) – Open March 19-29, 2012 ([Successive Ballots and Non-binding Polls](#))
- [Project 2010-07: Generator Requirements at the Transmission Interface](#) (FAC-003-X and FAC-003-3) – Open March 30 - April 9, 2012 ([Successive Ballot](#))
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Standard Drafting Team Vacancies

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 - [Project 2007-12 Frequency Response](#): Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

OTHER ITEMS

2012 Standards and Compliance Workshops

[Spring Reliability Standards and Compliance Workshop](#), April 16-18, 2012, [Manchester Grand Hyatt](#), San Diego, CA ([Register](#))

Fall Reliability Standards and Compliance Workshop, October 23-25, 2012, Westin Buckhead, Atlanta, GA (Agenda TBA)

Articles Posted

[Trustees Decide on Interpretation of COM-002-2](#) (posted on NERC's website)

[How NERC Makes Standards: Then, Now and Tomorrow](#) (posted at www.electricity-today.com, page 8)

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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From: [Monica Benson](#)
To: monica.benson@nerc.net
Subject: NERC: Standards Bulletin - March 19-25, 2012
Date: Monday, March 19, 2012 9:17:43 AM

Standards Bulletin March 19-25, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations 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 welcome. Please email [Monica Benson](#) with questions about standards commenting and balloting and [Mallory Huggins](#) with feedback on this bulletin.

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STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

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- [Project 2007-17: Protection System Maintenance and Testing](#) (PRC-005) – Open March 19-28, 2012 ([Successive Ballot and Non-binding Poll](#))
- [Project 2007-09: Generator Verification](#) (MOD-026-1 and PRC-024-1) – Open March 19-29, 2012 ([Successive Ballots and Non-binding Polls](#))

Posted for Comment (comment periods close at 8 p.m. Eastern)

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- [Project 2011-INT-02: Interpretation of VAR-002 for Constellation](#) – Open February 9, 2012 - March 23, 2012 ([Comment Form](#))
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- [Project 2010-07: Generator Requirements at the Transmission Interface](#) (PRC-005-1.1a) – Open March 2, 2012 - April 16, 2012 ([Comment Form](#))

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

- [Project 2007-09: Generator Verification](#) (MOD-025-2, MOD-027-1, and PRC-019-1) – Open February 29 - March 29, 2012 ([Join](#))
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Pending Ballots (ballot periods close at 8 p.m. Eastern)

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- [Project 2010-07: Generator Requirements at the Transmission Interface](#) (PRC-005-1.1a) – Open April 6-16, 2012 ([Initial Ballot](#))

Standard Drafting Team Vacancies

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OTHER ITEMS

2012 Standards and Compliance Workshops

[Spring Reliability Standards and Compliance Workshop](#), April 16-18, 2012, [Manchester Grand Hyatt](#), San Diego, CA ([Register](#))

Fall Reliability Standards and Compliance Workshop, October 23-25, 2012, Westin Buckhead, Atlanta, GA (Agenda TBA)

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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From: [Monica Benson](#)
To: monica.benson@nerc.net
Subject: NERC: Standards Bulletin - March 26 - April 1, 2012
Date: Monday, March 26, 2012 9:43:16 AM

Standards Bulletin

March 26 - April 1, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations 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 welcome. Please email [Monica Benson](#) with questions about standards commenting and balloting and [Mallory Huggins](#) with feedback on this bulletin.

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STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- [Project 2007-17: Protection System Maintenance and Testing](#) (PRC-005) – Open March 19-28, 2012 ([Successive Ballot and Non-binding Poll](#))
- [Project 2007-09: Generator Verification](#) (MOD-026-1 and PRC-024-1) – Open March 19-29, 2012 ([Successive Ballots and Non-binding Polls](#))
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- [Project 2007-03: Real-time Transmission Operations](#) (TOP-001-2, TOP-002-2, TOP-003-2, and PRC-001-2) – Open March 22 - April 20, 2012 ([Comment Form](#))

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

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Pending Ballots (ballot periods close at 8 p.m. Eastern)

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OTHER ITEMS

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From: [Monica Benson](#)
To: monica.benson@nerc.net
Subject: NERC: Standards Weekly Bulletin - April 2-8, 2012
Date: Monday, April 02, 2012 8:50:57 AM

Standards Bulletin

April 2-8, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations 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 welcome. Please email [Monica Benson](#) with questions about standards commenting and balloting and [Mallory Huggins](#) with feedback on this bulletin.

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STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- [Project 2010-07: Generator Requirements at the Transmission Interface](#) (FAC-003-X and FAC-003-3) – Open March 30 - April 9, 2012 ([Successive Ballot](#))
- [Project 2007-09: Generator Verification](#) (MOD-025-2, MOD-027-1, and PRC-019-1) – Open April 6-16, 2012 ([Initial Ballots and Non-binding Polls](#))
- [Project 2010-07: Generator Requirements at the Transmission Interface](#) (PRC-005-1.1a) – Open April 6-16, 2012 ([Initial Ballot](#))

Posted for Comment (comment periods close at 8 p.m. Eastern)

- [Project 2010-07: Generator Requirements at the Transmission Interface](#) (FAC-003-X and FAC-003-3) – Open March 9 - April 9, 2012 ([Comment Form](#))
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- [Project 2010-07: Generator Requirements at the Transmission Interface](#) (PRC-005-1.1a) – Open March 2, 2012 - April 16, 2012 ([Comment Form](#))
- [Project 2007-03: Real-time Transmission Operations](#) (TOP-001-2, TOP-002-2, TOP-003-2, and PRC-001-2) – Open March 22 - April 20, 2012 ([Comment Form](#))

Pending Ballots (ballot periods close at 8 p.m. Eastern)

- [Project 2007-03: Real-time Transmission Operations](#) (TOP-001-2, TOP-002-2, TOP-003-2, and PRC-001-2) – Open April 11-20, 2012 ([Successive Ballots](#))

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OTHER ITEMS

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[Hyatt](#), San Diego, CA ([Register](#) by April 2 for in-person and April 9 for webinar)

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Atlanta, GA (Agenda TBA)

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From: [Wendy Kinnard](#)
To: [Wendy Kinnard](#)
Subject: NERC: Standards Weekly Bulletin - April 9-15, 2012
Date: Monday, April 09, 2012 10:04:39 AM

Standards Bulletin April 9-15, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations 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 welcome. Please email [Monica Benson](#) with questions about standards commenting and balloting and [Mallory Huggins](#) with feedback on this bulletin.

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STANDARDS ITEMS

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- [Project 2007-12 Frequency Response](#): Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

OTHER ITEMS

Standards Committee Meetings

[Standards Committee Process Subcommittee](#), April 10, 2012 (8:00 a.m.-5:00 p.m. Eastern), Tampa, FL

[Standards Committee Communications and Planning Subcommittee](#), April 10, 2012 (1:00-5:00 p.m. Eastern), Tampa, FL ([Agenda](#))

[Standards Committee](#), April 11, 2012 (8:00 a.m.-5:00 p.m. Eastern) and April 12, 2012 (8:00 a.m.-5:00 p.m. Eastern), Tampa, FL ([Agenda](#))

[Regional Standards Group](#), April 12, 2012 (3:00-6:00 p.m. Eastern), Tampa, FL ([Agenda](#))

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Wendy J. Kinnard
Standards Development Administrative Assistant
North American Electric Reliability Corporation
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From: [Monica Benson](#)
To: monica.benson@nerc.net
Subject: NERC: Standards Bulletin - April 16-22, 2012
Date: Monday, April 16, 2012 9:36:10 AM

Standards Bulletin

April 16-22, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards-related items posted for industry comment or ballot, along with a list of upcoming standards-related postings and events. Please email [Monica Benson](#) with questions about standards commenting and balloting, [Caroline Clouse](#) with questions about CANs and RSAWs, and [Mallory Huggins](#) with feedback on this bulletin.

The current bulletin is always available on the [Standards Under Development page](#), and previous bulletins are available on the [Standards page](#).

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STANDARDS ITEMS

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- [Project 2007-03: Real-time Transmission Operations](#) (TOP-001-2, TOP-002-2, TOP-003-2, and PRC-001-2) – Open March 22 - April 20, 2012 ([Comment Form](#))
- [Project 2008-06: Cyber Security Order 706](#) (CIP-002-5 through CIP-0099-5, CIP-010-1, and CIP-011-1) – Open April 12, 2012 - May 21, 2012
 1. [Comment Form A: CIP-002 and CIP-003](#)
 2. [Comment Form B: CIP-004 through CIP-007](#)
 3. [Comment Form C: CIP-008 through CIP-001](#)
 4. [Comment Form D: Definitions and Implementation Plans](#)

Pending Ballots (ballot periods close at 8 p.m. Eastern)

- [Project 2008-06: Cyber Security Order 706](#) (CIP-002-5 through CIP-0099-5, CIP-010-1, and CIP-011-1) – Open May 11-21, 2012

Standard Drafting Team Vacancies

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the [Drafting Team Vacancies page](#) on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

OTHER ITEMS

Reliability Standard Audit Worksheets (RSAWs) Posted for Comment

- Comments due by April 30, 2012 to RSAWfeedback@nerc.net:
 - COM-002-2a: Communication and Coordination RSAW ([Redlined Draft](#))
 - PER-005-1: System Personnel Training RSAW ([Redlined Draft](#))

Compliance Application Notices (CANs) Posted for Comment

- Comments due by May 7, 2012 to cancomments@nerc.net using the [CAN Comment Form](#):
 - CAN-0019: CIP-007 R3.2, Implementation of Software Security Patches or Upgrades ([Draft with CCC Comments](#))
 - CAN-0023: CIP-005 R3 and CIP-006 R6, Logging System Failures ([Draft with CCC Comments](#))
 - CAN-0034: EOP-003 R1, IRO-002 R2, and TOP-001 R1, Use of Authority Letters ([Draft with CCC Comments](#))
 - CAN-0038: PER-002 R4, Training Hours ([Draft with CCC Comments](#))

Upcoming Events

- [Spring Reliability Standards and Compliance Workshop](#), April 16-18, 2012, Manchester Grand Hyatt, San Diego, CA ([Agenda](#), Slides, and Speaker Bios now posted)
- Fall Reliability Standards and Compliance Workshop, October 23-25, 2012, Westin Buckhead, Atlanta, GA

Website Updates

The Enforcement Dates pages for [Alberta](#), [British Columbia](#), [New Brunswick](#), and [Ontario](#) have been updated to include links to pages on the Canadian provinces' websites which include information on the standards approval process and their enforcement dates. NERC is working to ensure the accuracy and completeness of the enforcement dates and will continue to update the Enforcement Dates pages for the Canadian provinces as more

information is obtained and validated. These updates are intended to provide additional information in the interim as NERC works to update the Enforcement Dates pages for the Canadian provinces.

In addition, references to the term 'Mandatory Enforcement Dates' on NERC's website have been changed to 'Enforcement Dates' to reflect that NERC's enforcement authority in the Canadian provinces is limited and is determined by the provisions of the respective Memorandum of Understanding with each individual province. As part of this change, the URL for the former 'Mandatory Enforcement Dates' page has been changed to:

http://www.nerc.com/filez/standards/Enforcement_Dates.html.

Please email [Kristin Iwanechko](mailto:Kristin.Iwanechko@nerc.net) with any questions.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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From: [Wendy Kinnard](#)
To: [Wendy Kinnard](#)
Subject: NERC: Standards Weekly Bulletin - April 23-29, 2012
Date: Monday, April 23, 2012 12:00:18 PM

Standards Bulletin April 23-29, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards-related items posted for industry comment or ballot, along with a list of upcoming standards-related postings and events. Please email [Monica Benson](#) with questions about standards commenting and balloting, [Caroline Clouse](#) with questions about CANs and RSAWs, and [Mallory Huggins](#) with feedback on this bulletin.

The current bulletin is always available on the [Standards Under Development page](#), and previous bulletins are available on the [Standards page](#).

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email [Mallory Huggins](#).

STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- [Project 2009-26: Interpretation of CIP-004-1 for WECC](#) – Open April 20-30, 2012 ([Recirculation Ballot](#))
- [Interpretation 2010-INT-05: Interpretation of CIP-002-1 R3 for Duke Energy](#) – Open April 20-30, 2012 ([Recirculation Ballot](#))

Posted for Comment (comment periods close at 8 p.m. Eastern)

- [Project 2008-06: Cyber Security Order 706](#) (CIP-002-5 through CIP-0099-5, CIP-010-1,

and CIP-011-1) – Open April 12, 2012 - May 21, 2012

1. [Comment Form A: CIP-002 and CIP-003](#)
2. [Comment Form B: CIP-004 through CIP-007](#)
3. [Comment Form C: CIP-008 through CIP-001](#)
4. [Comment Form D: Definitions and Implementation Plans](#)

Pending Ballots (ballot periods close at 8 p.m. Eastern)

- [Project 2008-06: Cyber Security Order 706](#) (CIP-002-5 through CIP-0099-5, CIP-010-1, and CIP-011-1) – Open May 11-21, 2012

Standard Drafting Team Vacancies

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the [Drafting Team Vacancies page](#) on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

The latest posted vacancy is for the following:

- [Project 2010-13.2: Generator Relay Loadability](#): Seeking an individual with experience in generator protection systems from the FRCC or MRO region and either the cooperative or merchant electricity generator sector.

OTHER ITEMS

Reliability Standard Audit Worksheets (RSAWs) Posted for Comment

- Comments due by April 30, 2012 to RSAWfeedback@nerc.net:
 - COM-002-2a: Communication and Coordination RSAW ([Redlined Draft](#))

- PER-005-1: System Personnel Training RSAW ([Redlined Draft](#))

Compliance Application Notices (CANs) Posted for Comment

- Comments due by May 7, 2012 to cancomments@nerc.net using the [CAN Comment Form](#):
 - CAN-0034: EOP-003 R1, IRO-002 R2, and TOP-001 R1, Use of Authority Letters ([Draft with CCC Comments](#))
 - CAN-0038: PER-002 R4, Training Hours ([Draft with CCC Comments](#))
- Comments due by June 4, 2012 to cancomments@nerc.net using the [CAN Comment Form](#):
 - CAN-0019: CIP-007 R3.2, Implementation of Software Security Patches or Upgrades ([Draft with CCC Comments](#))
 - CAN-0023: CIP-005 R3 and CIP-006 R6, Logging System Failures ([Draft with CCC Comments](#))

Upcoming Events

- Fall Reliability Standards and Compliance Workshop, October 23-25, 2012, Westin Buckhead, Atlanta, GA

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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From: [Monica Benson](#)
To: monica.benson@nerc.net
Subject: NERC: Standards Bulletin - April 30-May 6, 2012
Date: Monday, April 30, 2012 9:28:16 AM

Standards Bulletin

April 30-May 6, 2012

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and other standards-related items posted for industry comment or ballot, along with a list of upcoming standards-related postings and events. Please email [Monica Benson](#) with questions about standards commenting and balloting, [Caroline Clouse](#) with questions about CANs and RSAWs, and [Mallory Huggins](#) with feedback on this bulletin.

The current bulletin is always available on the [Standards Under Development page](#), and previous bulletins are available on the [Standards page](#).

If you would like to be added to the distribution list for a particular standards project to stay informed about drafting team meetings and calls, please email [Mallory Huggins](#).

STANDARDS ITEMS

Current Ballots (ballot periods close at 8 p.m. Eastern)

- [Project 2009-26: Interpretation of CIP-004-1 for WECC](#) – Open April 20-30, 2012 ([Recirculation Ballot](#))
- [Interpretation 2010-INT-05: Interpretation of CIP-002-1 R3 for Duke Energy](#) – Open April 20-30, 2012 ([Recirculation Ballot](#))
- [Project 2010-07: Generator Requirements at the Transmission Interface](#) (FAC-003-X, FAC-003-3, and PRC-005-1.1b) – Open April 24-May 3, 2012 ([Recirculation Ballot](#))
- [Project 2007-03: Real-time Transmission Operations](#) —Open April 27-May 6, 2012 ([Recirculation Ballots](#))

Posted for Comment (comment periods close at 8 p.m. Eastern)

- [Project 2008-06: Cyber Security Order 706](#) (CIP-002-5 through CIP-0099-5, CIP-010-1, and CIP-011-1) – Open April 12, 2012 - May 21, 2012
 - [Comment Form A: CIP-002 and CIP-003](#)
 - [Comment Form B: CIP-004 through CIP-007](#)
 - [Comment Form C: CIP-008 through CIP-001](#)
 - [Comment Form D: Definitions and Implementation Plans](#)
- [Project 2009-01: Disturbance and Sabotage Reporting](#) (EOP-004-2) – Open April 25 - May 24, 2012 ([Comment Form](#))

Pending Ballots (ballot periods close at 8 p.m. Eastern)

- [Project 2008-06: Cyber Security Order 706](#) (CIP-002-5 through CIP-0099-5, CIP-010-1, and CIP-011-1) – Open May 11-21, 2012
- [Project 2009-01: Disturbance and Sabotage Reporting](#) (EOP-004-2) – Open May 15-24, 2012 ([Successive Ballot and Non-binding Poll](#))

Standard Drafting Team Vacancies

Any industry stakeholders interested in participating on a standards drafting team can view vacant appointments on the [Drafting Team Vacancies page](#) on NERC's website and submit a self-nomination form to sarcomm@nerc.com.

The latest posted vacancy is for the following:

- [Project 2010-13.2: Generator Relay Loadability](#): Seeking an individual with experience in generator protection systems from the FRCC or MRO region and either the cooperative or

merchant electricity generator sector.

Call for Standards Development Project Candidates

NERC is in the process of developing the 2013-2015 Reliability Standards Development Plan (the Plan). The Plan will be developed over the next several months, and will provide status updates for projects in development, identify the next projects scheduled for initiation, designate projects for further research, and catalog all proposed projects for future development.

- Summaries of the scope of each active project can be found in the [2012-2014 Plan, Appendix 4](#).
- Suggestions for a standards development project for the 2013-2015 Plan should be submitted via email to [Andy Rodriquez](#) using the new [Suggestion Form](#) no later than May 11, 2012.

OTHER ITEMS

Reliability Standard Audit Worksheets (RSAWs) Posted for Comment

- Comments due by April 30, 2012 to RSAWfeedback@nerc.net:
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[Form:](#)

- CAN-0019: CIP-007 R3.2, Implementation of Software Security Patches or Upgrades ([Draft with CCC Comments](#))
- CAN-0023: CIP-005 R3 and CIP-006 R6, Logging System Failures ([Draft with CCC Comments](#))

Revised Definition of Adequate Level of Reliability (ALR) and Supporting Documents Posted for Comment

- Comments on the following documents due by June 25, 2012:
 - [Definition: Adequate Level of Reliability for the Bulk Electric System](#)
 - [Technical Report Supporting Definition of Adequate Level of Reliability](#)
 - [Discussion Paper: Risk Tolerance for Widespread Bulk Electric System Outages](#)
 - [Discussion Draft: Mapping of Adequate Level of Reliability for the Bulk Electric System to Standards Development Reliability Principles](#)
 - *See also:* [Original Announcement](#) with background information on the Adequate Level of Reliability Task Force
- Submit comments using the [electronic comment form](#).

Upcoming Events

- [Member Representatives Committee Informational Webinar](#) (including several standards-related items for discussion), May 1, 2012, 11:00 a.m.-1:00 p.m. ([Register](#))
- Fall Reliability Standards and Compliance Workshop, October 23-25, 2012, Westin Buckhead, Atlanta, GA

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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**AMENDED AND RESTATED BYLAWS
OF
NORTHEAST POWER COORDINATING COUNCIL, INC.**
(a New York not-for-profit corporation)

Adopted on May 18, 2006

Amended on July 24, 2007

and April 15, 2011

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SCHEDULES

Schedule A – List of NPCC Members

Schedule B – Rules of Procedure (Selection of NPCC Directors)

AMENDED AND RESTATED BYLAWS

OF

NORTHEAST POWER COORDINATING COUNCIL, INC.

(a New York not-for-profit corporation)

ARTICLE I - DEFINITIONS

1.1 Definitions. As used herein, the following terms have the respective meanings set forth below:

“Affiliate” means, with respect to any entity, any other entity that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such entity, as determined in the sole discretion of the Board. For this purpose, “control” may be presumed by the direct or indirect ownership of ten percent (10%) or more of the outstanding voting capital stock or other equity interests having ordinary voting power. Notwithstanding the foregoing, “Affiliate” excludes any entity wholly-owned or controlled by a Canadian Provincial government.

“Board” means the Board of Directors of NPCC.

“Board Chair” means the independent non-executive chairman of the Board who is retained by NPCC pursuant to a separate Board-approved agreement.

“Bulk Power System” shall have the meaning in the United States set forth in Section 215 of the Federal Power Act, as amended (16 U.S.C. § 824 et seq.), and such meaning in Canada as is consistent with applicable Provincial regulatory and/or governmental authority determinations.

“Bylaws” means these Amended and Restated Bylaws of NPCC, as approved by the Members of NPCC on [____], 2011 and effective as of [____], 2011.

“Certificate of Incorporation” means the Certificate of Incorporation of NPCC filed with the Secretary of State of the State of New York, as may be amended from time to time.

“FERC” means the Federal Energy Regulatory Commission.

“Hearing Body” means a group comprising the Hearing Officer and two (2) Independent Directors (excluding the Board Chair) which has been authorized by NPCC to conduct and render decisions in a formal compliance hearing of any entity registered in the NERC compliance registry who is the subject of a notice of alleged violation, proposed penalty or sanction, contested mitigation plan or contested remedial action directive.

“Hearing Officer” means an individual employed or contracted by NPCC and designated by NPCC to preside over formal compliance hearings.

“*Independent Director*” means a director who satisfies the “independence” criteria in Section 6.7(b) and serves in Sector 8 (*Independent Directors*) of the Board.

“*NERC*” means the North American Electric Reliability Corporation, or any successor entity, which has been certified by FERC as the ERO pursuant to Section 215 of the Federal Power Act, as amended (16 U.S.C. § 824 et seq.).

“*Northeastern North America*” means the geographical area within the perimeter border enclosing the State of New York, the six New England States of the United States, and the Canadian Provinces of Ontario, Québec, New Brunswick and Nova Scotia, including any radial load or generation connecting to these systems.

“*NPCC*” means Northeast Power Coordinating Council, Inc., or any successor entity.

“*Stakeholder Director*” means a director who serves in one of the seven (7) stakeholder sectors of the Board described in Section 4.4.

1.2 Additional Defined Terms. Terms not defined in these Bylaws shall have the definitions set forth in the Federal Power Act, Part 39 of the regulations of the FERC, as further clarified in FERC’s April 19, 2007 Order 119 FERC ¶ 61,060, and if not defined in any of those sources, shall be defined in accordance with their commonly understood and used technical meanings in the electric power industry, including applicable codes and standards.

ARTICLE II - OFFICES

2.1 Principal Office. The principal office of NPCC shall be located in New York County, State of New York.

ARTICLE III - PURPOSE

3.1 Not-for-Profit Corporation. NPCC is operated as a New York not-for-profit corporation and is organized pursuant to the Not-for-Profit Corporation Law of the State of New York (“*N-PCL*”).

3.2 Purpose. The purpose of NPCC is to promote and enhance the reliable and efficient operation of the international, interconnected Bulk Power System in Northeastern North America through (i) the development of Regional Reliability Standards and compliance assessment and enforcement of continent-wide and Regional Reliability Standards, coordination of system planning, design and operations, and assessment of reliability, pursuant to an agreement with the Electric Reliability Organization (“*ERO*”) which designates NPCC as a Regional Entity and delegates authority from FERC, and by Memoranda of Understanding with applicable Canadian Provincial regulatory and/or governmental authorities (collectively, “*Regional Entity activities*”), and (ii) the establishment of regionally-specific reliability criteria, and the monitoring and enforcement of compliance with such criteria (collectively, “*Criteria Services activities*”). In the development of regionally-specific reliability criteria, NPCC, to the extent possible, facilitates the attainment of fair, effective and efficient competitive electric markets.

ARTICLE IV - MEMBERSHIP

4.1 List of Members. The Members of NPCC are listed on Schedule A attached hereto.

4.2 Eligibility. Upon suitable application describing the nature and activities of the applicant, additional entities shall be accepted by the Board as Members in the appropriate categories, defined as follows:

- (1) **General Membership** is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of the ERO that has an interest in the reliable operation of the Northeastern North American Bulk Power System. General Members that are also registered entities within the NPCC Region are subject to compliance with reliability standards, consistent with their registration, and are also entitled to receive additional services from the Regional Entity division of NPCC.
- (2) **Full Membership** shall be available to entities which are General Members that also participate in electricity markets in the international, interconnected bulk power system in Northeastern North America. Independent system operators (“ISOs”), regional transmission organizations (“RTOs”), Transcos and other organizations or entities that perform the Balancing Authority function operating in Northeastern North America are expected to be Full Members of NPCC. The New York State Reliability Council and any other sub-regional reliability councils which may be formed are also expected to be Full Members. Full Members are subject to compliance with regionally-specific more stringent reliability criteria for their generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area and which are identified utilizing a reliability impact-based methodology. Full Members are also subject to compliance with reliability standards, and are entitled to receive additional services from the Criteria Services division of NPCC.

4.3 Application as a Member.

(a) Any person or entity that is eligible to become a Member of NPCC in accordance with Section 4.2 may become either a General Member or a Full Member by completing and submitting to NPCC a membership application on a form prescribed by the Board. Any person or entity that applies to NPCC as a Member shall comply with the conditions and obligations of membership specified in these Bylaws. As an additional condition of membership in NPCC, each person or entity registering as a Member shall execute an agreement with NPCC, in a form to be specified by the Board, that such person or entity will hold harmless all Directors, officers, employees and agents of NPCC, as well as volunteers participating in good faith in the activities of NPCC, to the extent permitted by U.S. Federal or Canadian Provincial laws, rules and regulations, for any injury or damage caused by any act or omission of any Director, officer, employee, agent or volunteer in the course of performance of his or her

duties on behalf of NPCC, other than for acts of gross negligence, intentional misconduct or a breach of confidentiality.

(b) If not a natural person, the Member shall designate a representative and an alternate representative with authority to receive notices, cast votes, execute waivers and consents, and enter into binding agreements on behalf of the Member. NPCC shall maintain a current roster of the Members of NPCC, including each Member's designated representative and alternate representative. From time to time, the Board may establish a date by which Members shall submit their application renewals. All Members shall confirm their applications within thirty (30) calendar days of the date of receipt of request by NPCC, using an application renewal form prescribed by the Board. Any Member that has not submitted an application renewal within thirty (30) calendar days following the date established by the Board shall be removed from the NPCC roster. NPCC shall notify any Member that is removed from the roster of Members of such removal, by written notice sent to such former Member's last known address on the records of NPCC.

4.4 Voting. Members are eligible to vote in one of the seven (7) stakeholder voting sectors described below:

Sector (1). Transmission Owners: This voting sector shall consist of any entity within Northeastern North America that owns at least 200 circuit miles of integrated transmission facilities, or has an Open Access Transmission Tariff or equivalent on file with the FERC or the appropriate regulatory or governmental authority. This sector includes transmission owners that have placed their transmission under the operational control of an ISO/RTO, independent transmission companies and merchant transmission owners/developers.

Sector (2). Reliability Coordinators: This voting sector shall consist of any entity within Northeastern North America certified as a Reliability Coordinator.

Sector (3). Transmission Dependent Utilities ("TDUs"); Distribution Companies and Load-Serving Entities ("LSEs"). This voting sector shall consist of entities within Northeastern North America that are:

- (a) Entities with a regulatory contract, or other legal obligation to serve wholesale aggregators or end-use customers, and that depend primarily on the transmission systems of third parties to provide this service;
- (b) Agents or associates that represent groups of TDUs;
- (c) Electric distribution companies;
- (d) Entities serving end-use customers under a regulated tariff, a contract governed by a regulatory tariff, or other legal obligation to serve; or

- (e) Members of a generation and transmission (“G&T”) cooperative or a joint-action agency permitted to designate the G&T or joint action agency to represent such entities in this sector.

Sector (4). Generator Owners: This voting sector shall consist of entities within Northeastern North America that are affiliated and/or independent generators.

Sector (5). Marketers, Brokers and Aggregators: This voting sector shall consist of entities within Northeastern North America that are:

- (a) Entities providing energy to end-use customers under a power marketing agreement or other authorization not classified as a regulated tariff;
- (b) Entities that buy, sell, or broker energy and related services for resale in wholesale or retail markets, whether a non-jurisdictional entity operating within its charter or an entity licensed by a jurisdictional regulator; or
- (c) Generation and transmission cooperatives and joint-action agencies that perform an electricity broker, aggregator, or marketer function.

Sector (6). State and Provincial Regulatory and/or Governmental Authorities. This voting sector shall consist of State and Provincial regulatory or governmental authorities within Northeastern North America.

Sector (7). Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities: This voting sector shall consist of:

- (a) Any entity within Northeastern North America authorized by an appropriate regulatory and/or governmental authority to be a Sub-Regional Reliability Council;
- (b) Entities or customers that take delivery of energy that is not purchased for resale within Northeastern North America;
- (c) Agents or associations representing groups of large end users within Northeastern North America;
- (d) Agents, state consumer advocates, or other advocate groups representing groups of small customers within Northeastern North America;
- (e) Any other delegated Regional Entity; or
- (f) Any person or entity, including any entity participating in the Registered Ballot Body of the ERO, that has an interest in the

reliable operation of the bulk power system in Northeastern North America.

4.5 Assignment to Voting Sector. A new applicant for membership shall request to be assigned to a stakeholder voting sector, subject to Board approval. An applicant may request to be assigned to any stakeholder voting sector so long as membership in that stakeholder voting sector is consistent with the applicant's business or other activities within the NPCC region. Multiple memberships of separate business functions of an entity are permitted, with each business function assigned to the appropriate separate sector. Each such business function may designate its own representative and alternate, however, no representative and alternate can represent more than one business function of an entity in a stakeholder voting sector. A consultant, attorney, agent, vendor, trade or industry association, state, provincial or local consumer advocate organization that provides services to or otherwise represents the interests of the Members of one or more stakeholder voting sectors may elect to be assigned to one such stakeholder voting sector subject to Board approval. Entities may request to change their stakeholder voting sector designation during an Annual Meeting of Members of NPCC, subject to Board approval.

4.6 Term of Membership. Membership in NPCC shall be retained so long as a Member meets its respective qualifications, obligations, and conditions of membership as set forth in this Article IV.

ARTICLE V - ORGANIZATION OF NPCC

5.1 Member Representatives. Each Member shall designate a senior executive level representative and an alternate representative with full authority to act on its behalf in carrying out the work of NPCC.

5.2 Board of Directors. The business and affairs of NPCC shall be managed under the direction of the Board.

5.3 Officers. The officers of NPCC shall consist of a President and Chief Executive Officer (CEO), a Secretary and a Treasurer, with assistants as appropriate, and such additional officers as may be approved by the Members. Officers, except for the President and CEO, shall hold office for one (1) year or until the next Annual Meeting of Members of NPCC and until their successors are duly elected and qualified.

5.4 President and CEO. NPCC shall employ a President and CEO and staff, as required, to carry out NPCC's mission and to perform the functions of NPCC. The President and CEO shall be appointed by the Board and shall serve at the Board's discretion. In the event of a vacancy in the presidency, the Board shall appoint an interim President and CEO who shall serve until such time as the Board appoints a new President and CEO. The authority and responsibilities of the President and CEO shall be defined by the Board.

5.5 Vacancies.

(a) In the event a vacancy occurs in the Board, or in the office of Co-Vice Chair, Secretary, or Treasurer in the interim between Annual Meetings of Members of NPCC,

the Board Chair may designate (i) a person from the same stakeholder voting sector to fill such vacancy with the approval of a majority vote of the Directors, or (ii) in the case of a vacancy in the office of the Secretary or Treasurer, from outside of NPCC to fill such vacancy with the approval of a majority vote of the Directors.

(b) In the event a vacancy occurs in the office of Board Chair in the period between Annual Meetings of Members of NPCC, the Board may fill such vacancy by a two-thirds (2/3) affirmative majority of the weighted sector votes, with each Director casting one (1) vote within the applicable sector, at a meeting of the Board at which a quorum is present. The term of office of the persons designated to fill any such vacancy shall expire on the date of the next subsequent Annual Meeting of Members of NPCC. The authority and responsibilities of the Board Chair shall be defined by the Board and set forth in a separate agreement approved by the Board.

5.6 NPCC Activities. NPCC engages in (i) Regional Entity activities which are conducted by its Regional Entity division, and (ii) Criteria Services activities which are conducted by its Criteria Services division.

ARTICLE VI - BOARD OF DIRECTORS

6.1 Hybrid Board.

(a) The Board shall consist of fourteen (14) Stakeholder Directors, two (2) Independent Directors, an independent Board Chair and the President and CEO.

(b) While serving on the Board, the President and CEO shall not be entitled to vote on any Board matters.

(c) Two (2) Co-Vice Chairs from different voting sectors on the Board shall be selected by the Directors and approved by a vote of the entire membership. In the temporary absence of the Board Chair, a Vice Chair designated by a two-thirds (2/3) vote of the Directors shall perform the duties of the Board Chair. The Co-Vice Chairs shall retain the voting rights that they otherwise held by virtue of serving as a Director.

6.2 Term and Compensation.

(a) The term of office of each Stakeholder Director shall be two (2) years. Initial terms of Stakeholder Directors shall be staggered by the Board so that these Board members serve initial terms of one (1) or two (2) years. There shall be no limit on the number of terms which may be served by any Stakeholder Director. Stakeholder Directors shall serve without compensation, including when performing duties of a Co-Vice Chair.

(b) The term of office of each Independent Director shall be two (2) years. Independent Directors may serve up to three (3) terms for a maximum of six (6) years. Each Independent Director shall be entitled to receive compensation as the Board may from time to time determine in its sole discretion.

(c) The term of office of the Board Chair shall be two (2) years, with no limitations on the number of terms that may be served. Compensation arrangements of the Board Chair shall be contained in a separate written agreement approved by the Board.

6.3 Powers and Duties.

(a) The Board shall develop NPCC policies, direct the activities of NPCC, accept additional entities as Members, review and approve or modify Member voting sector assignment, and make assignments to the committees of NPCC. The Board shall (i) approve a Regional Delegation Agreement, and any amendments thereto, with the ERO that delegates authority from FERC and any additional agreements with appropriate Canadian Provincial regulatory and/or governmental authorities, (ii) approve and oversee NPCC's Regional Reliability Standards Development Process and submit Regional Standards to the ERO for adoption by FERC and appropriate Canadian Provincial regulatory and/or governmental authorities, (iii) approve the NPCC Compliance Monitoring and Enforcement Program and oversee the assessment and enforcement of mandatory compliance with Reliability Standards consistent with the Regional Delegation Agreement and agreements with Canadian Provincial regulatory and/or governmental authorities, and (iv) oversee NPCC's assessment and enforcement of mandatory compliance with regionally-specific more stringent reliability criteria through administration of the NPCC Reliability Compliance and Enforcement Program. The duties of the Board shall also include consideration and resolution of budgetary matters, including the levying of any special assessments and the determination of any annual membership fee for Full Members. Notwithstanding the foregoing, the Board may not amend these Bylaws or establish, modify or eliminate any of NPCC's Regional Reliability Standards or regionally-specific more stringent reliability criteria; nor may the Board add, modify, or eliminate voting sectors established pursuant to these Bylaws.

(b) To carry out the purposes of NPCC, the Board, acting through the President and CEO and NPCC staff, shall enlist such personnel from Members as may be necessary; and, within the limits of the annual budget, may employ such personnel, incur such administrative expenses, and retain such independent professional consulting services for NPCC and the committees of NPCC as it may deem desirable.

6.4 Board Composition. The Board shall consist of an independent Board Chair, the President and CEO, such officers as shall from time to time be determined by the Board, and Directors in eight (8) voting sectors comprising seven (7) stakeholder sectors and one (1) independent sector, as described below:

Sector (1). Transmission Owners (Maximum of 2, with no more than 1 per Balancing Authority Area)

Sector (2). Reliability Coordinators (Maximum of 2)

Sector (3). Transmission Dependent Utilities (“TDUs”); Distribution Companies and Load-Serving Entities (“LSEs”) (Maximum of 2)

Sector (4). Generator Owners (Maximum of 2)

Sector (5). Marketers, Brokers and Aggregators (Maximum of 2)

Sector (6). Regulators (Maximum of 2)

Sector (7). Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities (Maximum of 2)

Sector (8). Independent Directors (Maximum of 2)

6.5 Quorum and Voting Requirements for the Board.

(a) At any meeting of the Board, attendance in person or by proxy by at least one-half (1/2) of the Stakeholder Directors in each of at least sixty percent (60%) of the stakeholders sectors and at least one (1) Independent Director shall constitute a quorum. Except as otherwise expressly provided in NPCC's Certificate of Incorporation, these Bylaws or applicable law, actions by the Board shall be approved upon receipt of a two-thirds (2/3) affirmative majority of the weighted sector votes, with each Director casting one (1) vote within the applicable sector, at a meeting of the Board at which a quorum is present. The Board Chair shall also be entitled to cast one (1) vote during any meeting of the Board at which a quorum is present to prevent any deadlock. The following process shall be used to determine if there are sufficient affirmative votes:

- The number of votes cast is the sum of affirmative and negative votes, excluding abstentions.
- The number of affirmative votes cast in each voting sector will be divided by the sum of affirmative and negative votes cast in that voting sector to determine the fractional affirmative vote for each voting sector. Abstentions will not be counted for the purposes of determining the fractional affirmative vote for a voting sector.
- The sum of the fractional affirmative votes from all sectors divided by the number of sectors voting will be used to determine if a two-thirds (2/3) affirmative majority has been achieved. A sector will be considered as "voting" if any Director of the sector casts either an affirmative or a negative vote.

(b) An action of the Board will be approved if the sum of fractional affirmative votes from all sectors divided by the number of voting sectors is at least two-thirds (2/3).

6.6 Board Action Without Meeting. Any action required, or permitted to be taken at a meeting of the Board, may be taken without a meeting if the action is taken by all members of the Board. The action must be evidenced by one or more written consents (which may be in electronic form) describing the action taken, signed by each Director, and included in the minute book of NPCC. Any action taken under this Section 6.6 shall be deemed effective when the last Director signs the consent, unless the consent specifies a different effective date.

6.7 Election and Removal of Directors.

(a) The Initial Board shall be the persons named in the Certificate of Incorporation and shall serve until the first Annual Meeting of the Members. The Initial Board shall nominate a list of Stakeholder Directors consistent with the Board composition requirements set forth in Bylaws at such time. At the first meeting of the Members, the Members from each sector shall vote to elect the Stakeholder Directors in their respective sector. Stakeholder Directors shall be elected by a vote of the majority of the Members in the respective stakeholder sector. No stakeholder sector shall elect more than two Stakeholder Directors in such sector. No Member or any Affiliate of a Member may designate more than one (1) Stakeholder Director to represent such Member or Affiliate. Stakeholder Director candidates will be selected in accordance with the Rules of Procedure set forth in Schedule B.

(b) Individual Members may nominate an Independent Director candidate by petition. Each petition shall present only one Independent Director candidate who has met requirements in the Rules of Procedure set forth in Schedule B. Petitions shall be received by the Corporate Governance and Nominating Committee on a date set by the committee. The names on the petition shall reflect at least ten percent (10%) of the Members of NPCC as of January 1 of the year in which the election is to be held. Upon receipt of a valid petition, the Corporate Governance and Nominating Committee shall add the petitioned candidate's name to the slate of director nominees to be presented to the Members for approval at the Annual Meeting of Members.

(c) Independent Directors shall be nominated in accordance with the Rules of Procedure set forth in Schedule B and recommended by the Board to the Members for consideration and approval. In order to contribute to the effective functioning of the Board and NPCC, Independent Directors will be drawn from diverse backgrounds and will possess a broad range of industry expertise, perspectives, experiences, skill sets and knowledge. An individual is eligible to serve as an Independent Director if such individual (i) is not an officer or employee of NPCC, (ii) is not an officer, director or employee of a Member, (iii) is not an officer, director or employee of any entity that would reasonably be perceived as having a direct financial interest in the outcome of Board decisions, and (iv) does not have a relationship that would interfere with the exercise of independent judgment in performing the responsibilities of a director. Independent Directors shall be elected by an affirmative vote of the majority of the Members present at a meeting where a quorum exists.

(d) A Stakeholder Director may be removed for cause by at least two-thirds (2/3) of the Members in their respective sector at a regular meeting of the Members or at a special meeting called for that purpose; *provided* that there is a quorum of that sector's Members present at that meeting; and *provided, further*, that there is a quorum of not less than a majority present at the meeting of Directors at which such action is recommended.

(e) An Independent Director may be removed for cause by the affirmative vote of at least two-thirds (2/3) of the Directors present at a meeting called for that purpose; *provided* that there is a quorum of not less than ten (10) Directors present at the meeting of Directors at which such action is taken.

(f) For purposes of Section 6.7(d) and (e), grounds for removal “for cause” include, but are not limited to, failure to adequately perform Board duties and committee responsibilities, a felony conviction, misappropriation of funds, mental incapacity, and misconduct. In accordance with the N-PCL, an action to procure a judgment removing any Director for cause may also be brought by the Attorney-General of the State of New York.

6.8 Indemnification. Subject to the limitation set forth in Section 6.9 below, NPCC shall indemnify its Directors, officers, employees and other corporate agents, including volunteers participating in good faith in the activities of NPCC and persons serving on duly constituted committees of NPCC (collectively, “NPCC Indemnitees”), in each case, to the full extent from time to time permitted by the N-PCL and other applicable law. Such right of indemnification shall inure to the benefit of the legal representative of any NPCC Indemnitee. The foregoing right of indemnification shall be in addition to, and not in restriction or limitation of, any right such NPCC Indemnitee may have under applicable law (including the N-PCL).

6.9 Limitation on Indemnification. The maximum amount of losses (*i.e.*, damages, judgments, fines, penalties, liability, costs and expenses, including reasonable attorneys’ fees and expenses) for which NPCC will be obligated to indemnify the NPCC Indemnitees under Section 6.8 will be the policy limit of directors and officers’ (“D&O”) liability insurance set forth in the D&O insurance policy maintained by NPCC.

ARTICLE VII - COMMITTEES AND HEARING BODY

7.1 Number of Committees. NPCC shall have such committees, subcommittees, task forces and other groups as the Board may deem appropriate, including a Regional Standards Committee (RSC), a Compliance Committee (CC), a Reliability Coordinating Committee (RCC), NPCC’s principal technical committee), a Public Information Committee (PIC) and a Finance and Audit Committee (FAC).

7.2 Finance and Audit Committee. The Finance and Audit Committee shall be comprised of at least three (3) members of the Board and shall include one (1) Director which shall be designated a finance and audit committee financial expert by the Board. A chairperson of the Finance and Audit Committee shall be designated by the Board from among the members of the committee.

7.3 Committee Structure. Committee members shall be nominated and approved by the Board in accordance with guidelines established by the Board. Quorum and voting rules applicable to the Board shall also apply to voting on any such NPCC decision making committees, unless otherwise determined by the Board. Each committee shall establish a charter or scope of work, which shall be presented to the Board for approval.

7.4 Hearing Body. The Hearing Body shall conduct all compliance proceedings in accordance with the hearing procedures set forth in the NERC Hearing Procedure.

ARTICLE VIII - MEMBERS’ VOTING RIGHTS

8.1 Quorum and Voting Requirements for Meetings of Members.

(a) At any meeting of the Members of NPCC, attendance in person or by proxy by one-half (1/2) of the Members in each of at least sixty percent (60%) of the stakeholder voting sectors on the roster of Members maintained by NPCC shall constitute a quorum. Except as otherwise expressly provided in NPCC's Certificate of Incorporation, these Bylaws or applicable law, actions by the Members of NPCC shall be approved upon receipt of a two-thirds (2/3) affirmative majority vote of the sectors at a meeting of the Members of NPCC at which a quorum is present, where (i) each Member shall have one (1) vote within a sector, except that if less than one-half (1/2) of the Members in a sector are present, in person or by proxy, at the meeting, the vote of that sector shall be weighted by a percentage equal to the number of Members of the sector present in person or by proxy at the meeting divided by one-half (1/2) of the Members in the sector; (ii) the vote of each sector of NPCC shall be allocated for and against the proposed action based on the respective percentages of votes cast for and against the proposed action by the Members in that sector voting in person or by proxy; and (iii) the proportions of the votes of each sector allocated for and against the proposed action shall be summed to determine the total number of votes for and against the proposed action.

(b) The following process shall be used to determine if there are sufficient affirmative votes:

- The number of votes cast will be the sum of affirmative and negative votes, excluding abstentions.
- The number of affirmative votes cast in each sector will be divided by the sum of affirmative and negative votes cast to determine the fractional affirmative vote for each sector. Abstentions will not be counted for the purposes of determining the fractional affirmative vote for a sector.
- The sum of the fractional affirmative votes from all sectors divided by the number of sectors voting will be used to determine if a two-thirds (2/3) affirmative majority has been achieved. (A sector will be considered as "voting" if any Member of the sector casts either an affirmative or a negative vote.)

8.2 Waivers of Notice of Meetings of Members; Member Meeting Adjournments. Notice of a Meeting of Members need not be given to any Member who signs a waiver of notice, in person or by proxy, whether before or after the meeting. The attendance of any Member at a meeting, in person or by proxy, without protesting prior to the conclusion of the meeting the lack of notice of such meeting, shall constitute a waiver of notice of the meeting by such Member. When any Meeting of Members is adjourned to another time or place, it shall not be necessary to give notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken, and if at the adjourned meeting only such business is transacted as might have been transacted at the original meeting.

8.3 Actions Without a Meeting of Members. Any action, required or permitted to be taken at a Meeting of Members, may be taken without a meeting if the action is consented to in writing by the minimum number of Members that would be required to approve the action at a Meeting of Members at which all Members were present. The call for action without a Meeting

of Members may be initiated by the Board Chair or by a number of Members constituting at least ten percent (10%) of the Members on the roster of Members maintained by NPCC, which number shall include Members in at least four (4) of the voting sectors. Notice of the proposal for action without a meeting shall be provided to all Members on the roster of Members maintained by NPCC at least seven (7) days prior to the date established for the tabulation of consents. The Members shall receive written notice of the results within fourteen (14) days of the action vote, and all written responses of the Members shall be filed with the minutes of proceedings of Members.

8.4 Meeting of Members to be Open. Notice to the public of the dates, places, and times of Meetings of Members, and all non-confidential material provided to the Members, shall be posted on NPCC's web site at approximately the same time that notice is given to the Members. Meetings of Members shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; *provided* that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including, but not limited to, personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical energy infrastructure information of any entity.

8.5 Electronic Voting. Upon completion of applicable processes that permit parties to comment on the subject issue(s), electronic voting on matters before the Members, Board or any committee is permitted. A quorum will be determined to exist for purposes of conducting an electronic vote when NPCC receives completed ballots from two-thirds (2/3) of the total number of outstanding ballots. In the event that a quorum exists for purposes of an electronic vote but the matter has not been resolved, NPCC may continue to solicit additional responses in order to resolve the matter by electronic voting. In the event that quorum has not been achieved for purposes of an electronic vote, NPCC may continue to solicit electronic ballots, including abstentions, to obtain quorum and resolve the matter.

ARTICLE IX - MEMBERS' RIGHTS AND OBLIGATIONS, AND ORGANIZATIONAL PROCESS

9.1 Members' Rights and Obligations. All General and Full Members shall have the following rights and obligations:

- (1) Rights:
 - (a) Attendance at all meetings of the general membership of NPCC; and, subject to procedures established by the committees and to the terms of applicable confidentiality agreements, attendance at meetings of NPCC's committees, task forces and any other such NPCC groups.
 - (b) Access to minutes of each committee, subcommittee, task force or any other NPCC group, subject to procedures established by the committees and to the terms of applicable confidentiality agreements.
 - (c) Vote to amend these Bylaws in accordance with Section 19.1.

- (d) Vote to establish, modify or eliminate NPCC Regional Reliability Standards and programs.
 - (e) For Full Members only: Vote to establish, modify or eliminate NPCC's regionally-specific more stringent reliability criteria.
- (2) Obligations:
- (a) Each Member shall agree, in writing, to accept the responsibility to promote, support, and comply with the purposes and policies of NPCC as set forth in its Certificate of Incorporation and Bylaws as from time to time adopted, approved or amended.
 - (b) Each Member acknowledges that it has the responsibility to plan and design its bulk power system and conduct its operations, consistent with its registration, in compliance with ERO Reliability Standards, Regional Reliability Standards and Regional Variances consistent with applicable laws, regulations, permits and licenses.
 - (c) Each Member agrees to submit such data and reports as required by NPCC in order to perform compliance enforcement obligations delegated to it by the ERO, subject to established procedures and to the terms of applicable confidentiality agreements.
 - (d) In addition, each Full Member shall:
 - (i) plan and design its generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area, as identified utilizing a reliability impact-based methodology, in compliance with criteria, guides and procedures established by NPCC and applicable ERO Standards;
 - (ii) conduct its operations in compliance with criteria, guides and procedures established by NPCC and applicable ERO Standards, and consistent with applicable laws, regulations, permits and licenses;
 - (iii) assure that, whenever it enters into arrangements with non-members which could have an impact on the reliability of the international, interconnected Bulk Power System in Northeastern North America, the arrangements will not adversely impact the ability of the Full Members to comply with regionally-specific more stringent reliability criteria established by NPCC, ERO Standards, or the criteria of regional reliability organizations established in areas in which the facilities used for such arrangements are located;

- (iv) notify NPCC of its existing facilities and operating procedures and of its plans for major additions or modifications affecting the operation of the interconnected systems; and shall report to NPCC any decision as to significant alterations or changes proposed for their respective electric systems, whether in generation, transmission, inter-system communication or control and protective equipment, or in operating procedures; such report to be submitted promptly and, except in cases of emergency, before final commitments are undertaken or changes in operating procedures become effective;
- (v) promptly notify NPCC and all other Members in writing or electronically if its generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area, as identified utilizing a reliability impact-based methodology, are not being designed or operated, or its operations are not being conducted, in compliance with criteria, guides, and procedures established by NPCC, stating its reasons, and providing its plan and schedule to achieve compliance;
- (vi) submit such data and reports as required by the Reliability Compliance and Enforcement Program and to abide by the compliance assessments and sanctions prescribed by NPCC's enforcement procedures, subject to Alternative Dispute Resolution; and
- (vii) undertake and perform the administrative and financial obligations described in Article XIII of these Bylaws.

9.2 Standards Development Procedure. NPCC shall develop a Regional Reliability Standards Development Procedure that provides the design-basis approach to a consensus building process by which NPCC may develop Regional Reliability Standards and Regional Variances to be proposed to the ERO for adoption, under delegated authority by the FERC and the Canadian Provincial regulatory and/or governmental authorities.

9.3 Procedures for Enforcing Compliance with Reliability Standards. Where regulatory approval has been obtained or governmental authority has been provided, upon the determination of NPCC compliance staff and verification by the President and CEO that a user, owner or operator of the Bulk Power System has violated a reliability standard, NPCC shall enforce compliance for such violation, pursuant to procedures and processes that shall be specified in the NERC Compliance Monitoring and Enforcement Program. Such procedures and processes shall provide for reasonable notice and opportunity for hearing. Any sanction imposed for a violation of a Reliability Standard shall bear a reasonable relation to the seriousness of the violation and shall take into consideration circumstances surrounding the violation and efforts of the owner, operator, or user of the Bulk Power System to remedy the violation in a timely

manner. Subject to any necessary action by any applicable governmental authorities, no sanction imposed for a violation of a reliability standard shall take effect (i) until the thirty-first (31st) day after NPCC, where authorized by law or agreement, files with the FERC or other applicable Canadian Provincial regulatory and/or governmental authorities notice of the sanction and the record of the proceedings in which the violation and sanction were determined, or (ii) such other date as ordered by the FERC or other applicable Canadian Provincial regulatory and/or governmental authorities or as prescribed by applicable law.

ARTICLE X - FULL MEMBERS: ENFORCEMENT OF MANDATORY COMPLIANCE WITH REGIONALLY-SPECIFIC CRITERIA

10.1 Compliance Enforcement. Subject to approval of the Full Members, NPCC shall establish an NPCC Reliability Criteria Compliance and Enforcement Program, including matrices for measuring compliance, levying non-monetary sanctions, and developing procedures for Alternative Dispute Resolution. Such program shall be administered by the Board. The Reliability Coordinating Committee, with the full cooperation of each Member, shall expeditiously evaluate, as appropriate, alterations or measures designed to correct any assessed non-compliance and shall report such studies to the Board.

ARTICLE XI - MEETINGS

11.1 Meetings. Meetings of NPCC may be held on such dates as the Board may from time to time determine and shall be held in such places as the Board may from time to time designate. Special meetings may be called from time to time by the Board Chair, the Board or by a number of Members constituting at least ten percent (10%) of the Members on the roster of Members maintained by NPCC, which number shall include Members in at least four (4) of the voting sectors. Except as provided in Section 19.1, notice of all meetings, stating the time and place, shall be given by NPCC in writing to each Member by issuing the notice at least one (1) week prior to the date of the meeting. The Secretary, Assistant Secretary, or, in their absence, a secretary *pro tempore* designated by the Board Chair or the President and CEO, shall keep the records of NPCC meetings.

11.2 Proxies. When appropriate, Members, Directors and committee members may appoint a proxy, consistent with NPCC proxy procedures, to vote or otherwise act for such Member, Director or committee member at any meeting. Such participation by proxy shall constitute attendance for purposes of quorum requirements.

11.3 Action by Remote Communication. A meeting among the Members or the Board by means of a communication through which the participants may simultaneously hear each other during the conference shall constitute a meeting of the Members or the Board, as the case may be, if the same notice is given of the conference as would be required for a meeting and if the number of persons participating in such conference constitute a quorum. Participation in any meeting by this means shall constitute personal presence at such meeting.

ARTICLE XII - BUDGET

12.1 Annual Budget. The Board shall prepare or cause to be prepared an annual budget for the administrative and other expenses of NPCC, including the expenditures for the

fiscal year for any material special projects undertaken by NPCC and reasonable and proper reserves and provisions for contingencies, an accompanying business plan for NPCC, and a funding mechanism including any supplemental funding mechanism, for each fiscal year. The annual budget, business plan, and funding mechanism of NPCC shall be developed in the form and format and on the schedule stipulated by the ERO for a fiscal year commencing on January 1 and ending on December 31. Each annual budget, business plan, and funding mechanism shall be approved by the Board at a regular meeting or a special meeting of the Board duly called for that purpose. The Board shall approve each annual budget, business plan, and funding mechanism on or before the date stipulated by the ERO during the year prior to the start of the fiscal year in order to allow for timely submittal of the approved annual budget, business plan, and funding mechanism to the FERC and the applicable Canadian Provincial regulatory and/or governmental authorities.

12.2 Budget Remands. If the ERO or a regulatory and/or governmental authority by order remands an annual budget, business plan, or annual, modified, or supplemental funding mechanism, the Board shall promptly address such order through appropriate follow-up measures with the Members and regulatory and/or governmental authorities.

12.3 Criteria Services Budget. Each Full Member shall be notified of the annual administrative expense budget for the Criteria Services division, on or about December 1 of the preceding year.

ARTICLE XIII - FUNDING

13.1 Funding Sources. NPCC's annual administrative expenses, including any special assessments approved by the Board, shall be apportioned and funded as follows:

- A. Funding of NPCC General Member Regional Entity division activities shall be through mechanisms established by the ERO, FERC and applicable Canadian Provincial regulatory and/or governmental authorities.
- B. General Members shall not be assessed an annual membership fee.
- C. Full Members, other than Full Members that perform the Balancing Authority function, shall not be assessed an annual membership fee.
- D. Full Members that perform the Balancing Authority function shall be assessed and pay a proportional share of the expenses for criteria services in proportion to the ratio of the second previous year's Net Energy for Load within the Balancing Authority Area to the aggregate Net Energy for Load within all Balancing Authority Areas in Northeastern North America. NPCC will directly assign Criteria Services division costs to a Balancing Authority Area or entity where significant costs are incurred by NPCC for such Balance Authority Area or entity.
- E. No Full Member shall, without its consent, be responsible for expenses of NPCC in any one calendar year in excess of its assessed portion of the

amount budgeted for the Criteria Services division for that year; *provided, however*, that special assessments may be separately budgeted and their cost allocated by the Board to the Full Members that perform the Balancing Authority function.

ARTICLE XIV - TERMINATION OF MEMBERSHIP AND CESSATION OF CRITERIA SERVICES DIVISION RELIABILITY ACTIVITIES

14.1 Termination. All General Members and Full Members, other than Full Members that perform the Balancing Authority function, may terminate their membership in NPCC at any time upon fifteen (15) days' written or electronic notice without liability to NPCC. A Full Member that performs the Balancing Authority function may terminate its rights and obligations under these Bylaws (other than its obligation to pay its proportionate share of the Criteria Services division expenses of NPCC, including special assessments, if applicable, for the full calendar year within which such termination is effective) at any time upon one (1) year's written notice to the President and CEO; whereupon, it shall cease to be a Full Member of NPCC as of the date such termination is effective. The President and CEO shall promptly inform all Members of receipt of any such notices.

14.2 Cessation of Criteria Services Division Reliability Activities. The Full Members of NPCC may elect by a majority vote to cease Criteria Services division reliability activities.

ARTICLE XV - CONFLICTS OF INTEREST

15.1 Conflicts of Interest Policy. NPCC has developed a Code of Conduct that sets forth NPCC policies with respect to, among other things, conflicts of interest. On an annual basis, Directors shall evidence their compliance with NPCC conflict of interest principles by either: (i) signing an Individual Participant Implementation Agreement and thereby agreeing to comply with NPCC's Code of Conduct to the best of his/her ability; or (ii) agreeing that the execution of a Member Entity Implementation Agreement by the employer of such Director evidences the Director's agreement to be bound by its employer's Code of Conduct when performing NPCC activities. The Board shall establish similar Code of Conduct compliance requirements for NPCC staff and membership personnel participating on committees, task forces, and working groups as appropriate.

ARTICLE XVI - GENERAL

16.1 Member Liability. No Member shall be liable for the failure of any other Member to perform its obligations hereunder.

16.2 No Personal Liability. No NPCC officer, member of the Board or member of any other NPCC committee or group, or employee of NPCC shall be personally liable to NPCC or any member thereof, for damages for breach of any duty owed to NPCC or any member thereof, except for liabilities arising from breach of any duty based upon an act or omission (i) in breach of the duty of loyalty owed to NPCC or any individual member, (ii) not in good faith or involving a knowing violation of law, or (iii) resulting in receipt of an improper personal benefit by such NPCC officer, member of the Board or member of any other NPCC committee or group, or employee of NPCC. Neither the amendment nor repeal of this paragraph, nor the adoption of

any provision of these Bylaws inconsistent with this paragraph, shall eliminate or reduce the protection offered by this paragraph to an NPCC officer, member of the Board or member of any other such NPCC committee or group, or employee of NPCC in respect of any matter which occurred, or any cause of action, suit or claim which, but for this paragraph, would have accrued or arisen, prior to such amendment, repeal, or adoption.

16.3 Binding Nature. Those entities listed as Members on Schedule A and subsequent applicants granted membership in NPCC shall be deemed to have accepted and to be bound by all the terms and conditions of these Bylaws, as adopted on [____], 2011.

ARTICLE XVII - CONTRACTS, CHECKS, DEPOSITS

17.1 Contracts. The Board may authorize, by resolution, any officer or officers, agent or agents of NPCC, in addition to the officers so authorized by these Bylaws, to enter into any contract or execute and deliver any instrument in the name of and on behalf of NPCC, and such authority may be general or confined to specific instances.

17.2 Checks, Drafts or Orders. All checks, drafts or orders for the payment of money, notes or other evidences of indebtedness issued in the name of NPCC shall be signed by such officer or officers, or agent or agents of NPCC and in such manner as shall from time to time be determined by resolution of the Board. In the absence of such determination by the Board, such instruments shall be signed by the President and CEO.

17.3 Deposits. All funds of NPCC shall be deposited from time to time to the credit of NPCC in such banks, trust companies or other depositories as the Board may select.

ARTICLE XVIII - DISSOLUTION

18.1 Distribution of Assets. Upon dissolution of NPCC, in accordance with paragraph EIGHTH of the Certificate of Incorporation, the remaining assets of NPCC after payment of debts shall be distributed in the manner determined by the Board, provided that (i) no part of the assets shall be distributed to any Director, and (ii) the distribution of assets shall be consistent with the requirements of Section 501(c)(6) of the United States Internal Revenue Code of 1986, as amended.

ARTICLE XIX - AMENDMENT OF BYLAWS

19.1 Amendment of Bylaws. These Bylaws may be modified, amended or repealed by an affirmative vote of two-thirds (2/3) of the Members entitled to vote at a meeting at which quorum is present, or by electronic voting in accordance with Section 8.5. Written notice of the subject matter of the proposed changes to the Bylaws shall be provided, as appropriate, to the Members no less than fourteen (14) nor more than sixty (60) days prior to the date of the meeting of the Members at which the vote is to be taken. Any modification, amendment or repeal of these Bylaws shall be subject to any applicable requirements for filing with or approval by NERC and FERC and other applicable governmental authority.

ARTICLE XX - EFFECTIVE DATE

20.1 Effective Date. These Bylaws shall take effect on [_____], 2011.

SCHEDULE A – MEMBERS OF NPCC

[to be attached]

SCHEDULE B – RULES OF PROCEDURE (SELECTION OF NPCC DIRECTORS)

1. Selection of Director Candidates

In selecting candidates to serve as Stakeholder Directors and Independent Directors on the NPCC Board of Directors ("*Board*"), NPCC's Corporate Governance and Nominating Committee ("*CGNC*") will endeavor to find individuals of high integrity who have a solid record of accomplishment in their chosen fields and who display the independence of mind and strength of character to effectively represent the best interests of NPCC. Candidates will be selected for their ability to exercise good judgment, and to provide practical insights and diverse perspectives. Consistent with its charter, the CGNC is responsible for screening director candidates, establishing criteria for nominees, and recommending a slate of nominees to the Board for consideration. The slate of director nominees will be presented to the Members for approval at the Annual Meeting of Members.

2. Criteria for Board Service

The CGNC will consider and recruit candidates for director nominees based upon recommendations from Members, current directors, NPCC management, outside consultants or search firms engaged for the purpose, and any other source recommended by the Board. All candidates recommended will be evaluated for nomination based on the criteria set forth below:

- (a) Stakeholder Directors must reflect the geographic diversity of the NPCC Region, which comprises the State of New York, the six New England States of the United States, and the Canadian Provinces of Ontario, Québec, New Brunswick and Nova Scotia.
- (b) Directors must possess corporate and business experience at the senior-executive level, or the equivalent thereof.
- (c) Each Stakeholder Director must be an officer or senior executive-level employee of a Member of NPCC.
- (d) Each Independent Director must be an individual who:
 - (i) is not an officer or employee of NPCC;
 - (ii) is not an officer, director or employee of a Member;
 - (iii) is not an officer, director or employee of any entity that would reasonably be perceived as having a direct financial interest in the outcome of Board decisions; and
 - (iv) does not have a relationship that would interfere with the exercise of independent judgment in performing the responsibilities of a director of NPCC.
- (e) Directors must have no actual or potential conflicts of interests that would or could interfere with the diligent performance of the responsibilities of a Board member in the best interests of NPCC.



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Northeast Power Coordinating Council, Inc.

Regional Reliability Standards Process Manual

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**Approved by NPCC Board of Directors
XXXX XX, 20XX**

Approved by NERC Board Of Trustees XXXX XX, 20XX

Adopted by FERC XXXX XX, 20XX

NPCC

REGIONAL RELIABILITY STANDARDS PROCESS MANUAL

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I. EXECUTIVE SUMMARY

The purpose of the Northeast Power Coordinating Council, Inc. ("NPCC"), is to enhance the reliability of the international, interconnected Bulk power Electric System in Northeastern North America through the development of more stringent and specific regional reliability standards and compliance assessment and enforcement of continent-wide and regional reliability standards pursuant to the execution and implementation of a Regional Delegation Agreement with the Electric Reliability Organization ("ERO") and applicable Canadian Memoranda of Understanding that are backstopped by the Federal Energy Regulatory Commission ("FERC") and Canadian Provincial authorities. In the development and enforcement of Regional Reliability Standards, NPCC, to the extent possible, facilitates attainment of fair, effective, efficient, and competitive electric markets.

General Membership in NPCC is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of the ERO that has an interest in the reliable operation of the Northeastern North American Bulk Electric System.

This NPCC Regional Reliability Standards Process Manual describes the procedures, policies and practices approved by NPCC members and implemented to ensure an "open, fair, and inclusive" process for the transparent initiation, development, implementation and revision of NPCC Regional Reliability Standards necessary for the reliable operation of the international and interconnected Bulk Electric System in Northeast North America. These Standards will, in all cases, not be inconsistent with or less stringent than any requirements of the North American Electric Reliability Council/Electric Reliability Organization (NERC/ERO) Reliability Standards. Each regional reliability standard shall enable or support one or more NERC/ERO reliability principles¹, thereby ensuring that each standard serves a purpose in support of the reliability of the regional Bulk Electric System. Each standard shall also be consistent with all of pertinent reliability principles, thereby ensuring that no standard undermines reliability as an unintended consequence.

II. REGIONAL RELIABILITY STANDARDS PROCESS

1. CHARACTERISTIC ATTRIBUTES

The NPCC Regional Reliability Standards Process is:

- **Open** — The NPCC Regional Reliability Standards Process provides any person or entity that is directly and materially affected by the reliability of the NPCC's Bulk Electric System the ability to participate in the development and approval of reliability standards. Comments can be submitted by any person or entity. NPCC utilizes a Website to accomplish this. Online posting and review of standards and the real time sharing of comments uploaded to the

1. Available on the NERC Website: www.nerc.com.

Website allow complete transparency. There are no undue financial barriers to participation. Participation in the open comment process is not conditional upon membership in the ERO, NPCC or any organization, and participation is not restricted on the basis of technical qualifications or other such requirements.

- **Inclusive** — The NPCC Regional Reliability Standards Process provides any person with a direct and material interest the right to participate by expressing an opinion and its basis; have that position considered; and, in the event they are not satisfied with the response to their opinion, appeal the response through an established appeals process if desired.
- **Balanced** — The NPCC Regional Reliability Standards Process seeks to achieve a balance of interests; shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter. This will be accomplished through the NPCC Bylaws² which define six sectors (categories) for voting. All individuals and entities that are directly and materially affected by the reliability of the NPCC's Bulk power Electric System are welcome to participate
- **Fair Due Process** — The NPCC Regional Reliability Standards Process provides for reasonable notice and opportunity for public comment. The procedure includes public notice of the intent to develop a standard; a 45 calendar day public comment period on the proposed standard request or standard; due consideration of those public comments; and responses to those comments to be posted on the NPCC Website. A final draft of the notice of intent to develop the standard or the draft standard itself (both the clean and redline versions) along with the responses to comments will be posted for a 30 calendar day pre-balloting period, after which a ballot of NPCC Members will be conducted. ~~Voting is open to NPCC members only.~~ Upon approval by the NPCC Members, the NPCC Board then votes to approve submittal of the Regional Reliability Standard to NERC.
- **Transparent** — All actions material to the development of Regional Reliability Standards are transparent and information regarding the progress of a standards development action is made available to the public through postings on the NPCC Website as well as through E-mail lists.

In as much as NPCC is one of several regional entities within the Eastern Interconnection of North America, there will be **no presumption of validity** by the ERO for any NPCC Regional Reliability Standard. In order to receive the approval of the ERO, the NPCC Reliability Standards Development Process must also achieve the following objectives:

- **No Adverse Impact on Reliability of the Interconnection** — A NPCC Regional Reliability Standard provides a level of Bulk Electric System reliability that is necessary and adequate to protect public health, safety, welfare, and North American security and will not have an adverse impact on

2. Available on the NPCC Website: www.npcc.org

the reliability of the Interconnection or other Regions within the Interconnection.

- **Justifiable Difference** — A NPCC ~~Regional Reliability S~~standard is based on justifiable differences between Regions, such as different electrical systems or facilities, sensitivity of load to disruptions, sensitivity of generation to disruptions, frequency and voltage sensitivity, system operating limit development and facilities ratings process, electrical system interactions, etc. Comment: Given the new 100kV BES definition, will some of these differences persist? Issues and differences will still exist. Comment to be answered. Chris de Graffenried submitted the comment.
- **Uniformity**- NPCC ~~Regional Reliability S~~standards shall provide for as much uniformity as possible with reliability standards across the interconnected ~~Bulk power Electric s~~System of the North American continent. A NPCC ~~Regional Reliability S~~standard shall be ~~more~~no less -stringent and may be more specific than a continent-wide reliability standard; may include a regional variation that addresses matters that the continent-wide reliability standard does not; or shall be justified by a regional difference necessitated by a physical difference³ or operating difference in the northeast's Bulk Electric System.
- **No Undue Adverse Impact on Commerce** — An NPCC ~~Regional Reliability S~~standard will not cause any undue adverse impact on business activities that are not necessary for reliability of the Region and its interconnected Regions. All regional reliability standards shall be consistent with NERC's market principles⁴.

Other provisions of the NPCC Regional Reliability Standards Process include:

- **Maintenance of Regional Reliability Standards**-NPCC ~~Regional Reliability S~~standards will be -posted for open process review by the RSC for possible revision at least once every five (5) years after the first regulatory approval and follow the same process as in the case of a new standard. If no changes are warranted, the Regional Standards Committee (RSC) shall recommend to the NPCC Board that the standard be reaffirmed. If the review indicates a need to revise or ~~withdraw~~ retire a regional standard, a Regional Standard Authorization Request shall be prepared by the RSC and submitted in accordance with the NPCC Regional Reliability Standards Process. The existing, approved standard subject to revision will remain in effect until such time as the revised version has received FERC or applicable Provincial Governmental Authorities ~~Canadian Regulatory Authority~~ approvals, as

3. The interpretation of the phrase "physical difference" will be consistent with FERC's Order, issued September 22, 2004, Granting Request For Clarification regarding Docket No. PL04-5-000, Policy Statement on Matters Related to Bulk Power System Reliability.

4. Available on the NERC Website: www.nerc.com

appropriate, at which point it will be retired in accordance with any applicable implementation plan associated with the newly approved regional standard. (Comment: Why can't RSC make errata changes as allowed by NERC for continent-wide reliability standards?) Want to be able to do this. Define process later in the document. This has been addressed.

- Maintenance of the Regional Reliability Standards Process**--This NPCC Regional Reliability Standards Process will be reviewed for possible revision at least once every five (5) years, or more frequently, if needed, and subject to the same procedure as applies to the development of a Regional Reliability Standard. All such revisions shall be subject to approval by the NPCC Board of Directors, NERC Board of Trustees, FERC, and ~~could~~ may be subject to approval, if required, by applicable Governmental Authorities in Canada. Comment: Why can't RSC make 'errata' changes as allowed by NERC for continent-wide reliability standards or in regional reliability standards, (see page 9)? ok This has been addressed.
- Errata Changes to an approved Regional Standard**--From time to time, an error may be discovered in an approved Regional Standard. NPCC Staff will notify the RSC. If the RSC agrees that the correction of the error does not change the scope or intent of the associated standard, and agrees that the correction has no material impact on the end users of the standard, then the correction shall be submitted for information to the NPCC Board of Directors and provided to NERC for filing with the FERC and applicable Provincial Authorities.
- Interpretation of Standards**-- An interpretation request will be deemed valid if it is one that requests additional clarity about one or more requirements in an approved Regional Standard, but does not request approval as to how to comply with one or more requirements. A valid interpretation response provides additional clarity about one or more requirements, but does not expand on any requirement and does not explain how to comply with any requirement. Any entity that is directly and materially affected by the reliability of the North American Bulk Electric Systems may request an interpretation of any requirement in any Regional Standard that has been adopted by the NERC Board of Trustees. ~~All persons who are directly and materially affected by the NPCC's Bulk Electric System reliability shall be permitted to request an interpretation of a NPCC regional reliability standard. The person~~ entity requesting an interpretation shall send a written request to NPCC Standards Staff (npccstandard@npcc.org) ~~the Manager of Reliability Standards, as noted on the NPCC Website,~~ explaining the specific circumstances surrounding the request and what clarifications are required as applied to those circumstances. The request shall indicate the direct and material impact to the requesting party or others caused by the lack of clarity or a possibly incorrect interpretation of the regional standard. The NPCC Standards Staff, ~~Manager of Reliability Standards~~ along with guidance from the RSC will forward the request to the Task Force/Drafting Team ~~to whom responsibility was originally assigned for drafting the regional reliability standard.~~ regional reliability standard. If the original Task Force/Drafting Team is no longer available or assembled, then a new Task Force/Drafting

Team shall be assembled. ~~The~~ The Task Force/Drafting Team will address the request for clarification as soon as practical, but not more than 45 business days following ~~from its~~ receipt of the clarification request. ~~by the Task Force.~~ This ~~written~~ interpretation upon approval by the RSC will be posted along with the affected Regional Standard ~~final approved and adopted regional standard~~ for a 45 day comment period. The Task Force/Drafting Team will respond to the comments and forward the final recommendation to the RSC. This recommendation will be ~~either a proposal for revising the standard with a temporary clarification, and/or~~ may include a proposal for revising a Standard ~~a clarification.~~ The clarification ~~or temporary clarification~~ upon requisite approvals, will stand until such time as the regional standard is revised through the normal RSAR process, at which time the regional standard will ~~be modified to incorporate~~ address the ~~clarifications~~ issues raised ~~provided by the interpretation.~~

2. ELEMENTS OF A REGIONAL RELIABILITY STANDARD

• **Elements of a Regional Reliability Standard**

To ensure uniformity of regional reliability standards and avoid inconsistency with NERC continent-wide standards, a regional reliability standard shall be consistent with ~~of the~~ the elements identified in this section of the procedure. These elements are intended to apply a systematic discipline in the development and revision of regional standards. This discipline is necessary for achieving regional standards that are measurable, enforceable, and consistent as well as results oriented;^{5,6} i.e.

- Performance-based,
- Risk-based, and
- Capability-based.

The Standard Drafting Team (SDT) should strive to achieve a portfolio of performance, risk, and capability-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a) **Performance-based** - defines a specific reliability objective or outcome that has a direct, observable effect on the reliability of the NPCC ~~Bulk power~~ Electric ~~System~~, i.e. an effect that can be measured using power system data or trends.

b) **Risk-based** - defines actions of entities that reduce a stated risk to the reliability of the NPCC ~~Bulk power~~ Electric ~~System~~ and can be measured by evaluating a particular product or outcome resulting from the required actions.

5. Results-based Standards see http://www.nerc.com/filez/standards/Project2010-06_Results-based_Reliability_Standards.html.

6. ~~Results-based Standards presentation: <http://www.nerc.com/files/Results-Based-Standards-102010.pdf>.~~

c) **Capability-based** - defines capabilities needed to perform reliability functions and can be measured by demonstrating that the capability exists as required.

Each regional reliability standard shall enable or support one or more of the reliability principles as identified in the most recent set posted on the NERC website. Each reliability standard shall also be consistent with all of the reliability principles. The intent of the set of NPCC regional reliability standards is to deliver an Adequate Level of Reliability as defined by NERC.

Recognizing that Bulk Electric System reliability and electricity markets are inseparable and mutually interdependent, all regional reliability standards shall be consistent with the most recent set of Market Interface Principles as posted on the NERC website. Consideration of the Market Interface Principles is intended to ensure that regional reliability standards are written such that they achieve their reliability objective without causing placing undue restrictions or causing adverse impacts on competitive electricity markets.

~~Elements of a Regional Reliability Standard~~

~~A regional reliability standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the bulk power system. The components of a regional reliability standard include mandatory and enforceable sections and informational sections of the standard.~~

~~Mandatory and Enforceable Sections of a Standard typically include the following:~~

~~Title:~~ A brief, descriptive phrase identifying the topic of the standard.

~~Number:~~ A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the standards.

~~Purpose:~~ The reliability outcome achieved through compliance with the requirements of the standard.

~~Applicability~~

~~Effective Dates:~~ Identification of when each requirement becomes effective in each jurisdiction.

~~Requirement:~~ An explicit statement that identifies the functional entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each requirement shall be a statement for which compliance is mandatory.

~~Measure:~~ Provides identification of the evidence or types of evidence needed to demonstrate compliance with the associated requirement. Each requirement

~~shall have at least one measure. Each measure shall clearly refer to the requirement(s) to which it applies.~~

~~Evidence Retention: Identification, for each requirement in the standard, of the entity that is responsible for retaining evidence to demonstrate compliance, and the duration for retention of that evidence.~~

~~Variance: A requirement (to be applied in the place of the continent-wide requirement), and its associated measure and compliance information, that is applicable to a specific geographic area or to a specific set of functional entities.~~

Informational Sections of a Standard

~~Application Guidelines: Guidelines to support the implementation of the associated standard.~~

~~Procedures: Procedures to support implementation of the associated standard.~~

~~Time Horizon: The time period an entity has to mitigate an instance of violating the associated requirement.⁴~~

~~Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated standard.~~

~~Compliance Monitoring and Assessment Processes: Identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated standard.~~

~~Additional Compliance Information: Any other information related to assessing compliance such as the criteria or periodicity for filing specific reports.~~

Compliance Elements Associated with a Standard

~~Violation Risk Factors and Violation Severity Levels: Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved reliability standard. Each requirement in each regional standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NPCC staff, at the same time as the associated regional standard, but are not part of the regional standard. The NPCC Board of Directors is responsible for approving VRFs and VSLs.~~

Violation Risk Factors

~~VRFs identify the potential reliability significance of non-compliance with each requirement. Each requirement is assigned a VRF in accordance with the latest approved set of VRF criteria.~~

Violation Severity Levels

~~VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of non-compliant performance and may have only one,~~

~~two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria.~~

~~The most current version of the approved NERC Reliability Standard template and its associated elements as or if applicable, will be used at the time of the development of the NPCC Regional Reliability Standard to ensure all essential elements are contained therein to achieve consistency and uniformity and meet all statutory requirements.~~

A reliability standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the Bulk Electric System. The components of a reliability standard include mandatory requirements, elements necessary to demonstrate compliance and monitor and assess compliance with requirements, and informational sections of the standard.

Requirements and Elements, in accordance with the most recent version of the NERC Standards Processes Manual, necessary to Demonstrate Compliance and Monitor and Assess Compliance with Requirements, such as:

Title: A brief, descriptive phrase identifying the topic of the standard.

Number: A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the standards.

Purpose: The reliability outcome achieved through compliance with the requirements of the standard.

Effective Dates: Identification of when each requirement becomes effective in each jurisdiction.

Requirement: An explicit statement that identifies the functional entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each requirement shall be a statement for which compliance is mandatory.

Measure: Provides identification of the evidence or types of evidence needed to demonstrate compliance with the associated requirement. Each requirement shall have at least one measure. Each measure shall clearly refer to the requirement(s) to which it applies.

Evidence Retention: Identification, for each requirement in the standard, of the entity that is responsible for retaining evidence to demonstrate compliance, and the duration for retention of that evidence.

Variance: A requirement (to be applied in the place of the continent-wide requirement), and its associated measure and compliance information, that is applicable to a specific geographic area or to a specific set of functional entities.

Time Horizon: The time period an entity has to mitigate an instance of violating the associated requirement.⁴

Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated standard.

Compliance Monitoring and Assessment Processes: Identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated standard.

Additional Compliance Information: Any other information related to assessing compliance such as the criteria or periodicity for filing specific reports.

Violation Risk Factors and Violation Severity Levels: Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved reliability standard. Each requirement in each reliability standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NERC staff, at the same time as the associated reliability standard, but are not part of the reliability standard. The Board of Trustees is responsible for approving VRFs and VSLs.

Violation Risk Factors

VRFs identify the potential reliability significance of noncompliance with each requirement. Each requirement is assigned a VRF in accordance with the latest approved set of VRF criteria⁶.

Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria⁷.

Informational Sections of a Standard

Application Guidelines: Guidelines to support the implementation of the associated standard.

Procedures: Procedures to support implementation of the associated standard.

3. KEY PARTICIPANTS, ROLES, TERMS AND FUNCTIONS

COMMENT: There is no mention of who is to perform a quality review. Need to add this to the appropriate body's role. Is it the RSC's role? Legal, technical writer, and compliance and standards staff shall comprise the quality review team.

- **NPCC Board of Directors (~~BOD, Board~~)** - The NPCC Board Of Directors shall consider for adoption regional reliability standards, definitions, variances, interpretations and associated implementation plans that have been processed according to the processes identified in this manual. In addition, the Board shall consider for approval, VRFs and VSLs, Implementation Plans, associated with each member approved regional standard. Once the Board Of Directors adopts a regional reliability standard, definition, variance, interpretation or implementation plan, or once the Board Of Directors approves separate VRFs or VSLs, the Board of Directors shall direct NPCC staff to submit the document(s) for approval by the NERC Board of Trustees.
- **NPCC Members** - The ballot body is comprised of all entities or individuals that qualify for one of the stakeholder sectors within NPCC as stated in the most recently approved NPCC Bylaws. All General and Full Members of NPCC can participate in the balloting of regional standards. Any entity or person may submit comments during comment periods for standards including non-NPCC members.

- **Regional Standards Committee (RSC)**—A NPCC Board Of Directors appointed committee charged with management and oversight of the NPCC Regional Reliability Standards Process for development of regional standards, VRFs, VSLs, definitions, variances, interpretations, and implementation plans in accordance with this manual, under the sector based voting structure described in the NPCC Bylaws.

RSC membership is open to NPCC members and consists of a balance of stakeholder interests that provide for or are materially impacted by the reliability of the Bulk Electric System. Its responsibilities are defined in detail in the NPCC RSC Scope posted on the NPCC Website

- =The NPCC RSC will consider requests for new or revised regional reliability standards and be available ~~for advice~~ to advise the NPCC Board Of Directors on the regional standards, and standards related issues in general.

The RSC may not itself modify mandatory and enforceable sections of a regional= standard except in the event of minor corrections of a standard such as errata. The RSC may make revisions to the sections of the regional standard that are not mandatory and enforceable.

The RSC is responsible for ensuring that the regional standards, VRFs, VSLs definitions, variances, interpretations, ~~and~~ implementation plans, and any supporting documents developed by drafting teams are developed in accordance with the processes in this manual and meet NERC's and FERC's benchmarks for reliability standards including criteria for all governmental approvals.

The RSC disposition regarding the Regional Standard Authorization Request (RSAR), which will in all cases be within sixty (60) calendar days of receipt of a completed RSAR, shall be one ~~for~~ of the following:

- Accept the standard request as a candidate for development of a new standard, revision of an existing standard, or deletion of an existing standard. The RSC may, at its discretion, expand or narrow the scope of the standard request under consideration. The RSC shall prioritize the development of standards in relation to other proposed standards, as may be required based on the volume of requests and resources.
- Reject the standard request. If the RSC rejects a standard request, a written explanation for rejection will be delivered to the requester within 30 calendar days of the decision.
- Remand the standard request back to the requester for additional work. The NPCC standards staff will make reasonable efforts to assist the requester in addressing the deficiencies identified by the RSC. The requester may then resubmit the modified standard request using the

process above. The requester may choose to withdraw the standard request from further consideration prior to acceptance by the RSC.

The NPCC Standard Process responsibilities of the RSC include:

- Oversight of all Drafting Team activities. ~~The Drafting Team, a~~ After it is assigned by the RCC, the Drafting Team shall report to the RSC.
 - Review of NPCC Draft Standards (for such factors as completeness, sufficient detail, rational result, and compatibility with existing NERC and other Regional standards), and clarify standard development issues not specified in this procedure. Under no circumstance will the RSC unilaterally make any substantive changes to the ~~mandatory~~ mandatory and enforceable sections of a draft standard.
 - Ensure that the drafting team has given due consideration to the comments of all stakeholders ~~and minority objections~~, in approving a proposed regional reliability standard which is to go to ballot.
 - Approve posting of draft standards for pre-ballot ~~posting~~ review under a sector based voting structure as described later in the NPCC Bylaws; or
 - Remand the draft regional standard back to the Task Force acting as the drafting team for further work or recommend a change in those participating in the drafting team (i.e. a new drafting team).
-
- **NPCC Standards Staff** — The standards staff, ~~led by the Assistant Vice-President of Standards~~, is responsible for assisting the RSC in administering NPCC's Regional Reliability Standards Processes in accordance with this manual. The standards staff provides support to the RSC in managing the standards processes and in supporting the work of all regional drafting teams. The standards staff works to ensure the integrity of the standards processes and consistent quality and completeness of the regional standards, through drafting team support and conducting quality reviews. The standards staff facilitates all steps in the development of regional standards, definitions, variances, interpretations and associated implementation plans. The standards staff works with drafting teams in developing VRFs and VSLs for each regional standard.

The standards staff is responsible for presenting members' approved regional standards, definitions, variances, interpretations and associated implementation plans to the NPCC Board Of Directors for adoption. When presenting standards-related documents to the NPCC Board Of Directors for adoption or approval, the standards staff shall report the results of the associated stakeholder ballot, including identification of unresolved stakeholder objections and an assessment of the documents' practicality and enforceability as well as any polling information obtained during standard development.

- **Reliability Coordinating Committee (RCC)** —The RCC, will support the standards development process through the assignment of NPCC Task Forces

to serve as the foundation for Drafting Team formation. The RCC may also perform a technical advisory role in the Regional Reliability Standards Process through comments and recommendations. Need words for RCC involvement with supplying technical justification, etc.

- **Requester**— A Requester is any individual or an entity (organization, company, government authority, including the RSC, etc.) that submits a completed request for development, revision, or withdrawal of a regional standard. Any person or an entity that is directly and materially affected by an existing standard or the need for a new standard may submit a request for a new standard or revision to a standard. The Requester is assisted by the RSAR drafting team (if one is appointed by the RSC) or NPCC standards staff to complete the drafting of the RSAR prior to it being forwarded to the RSC with a request to draft a regional standard. The Requester is responsible for the RSAR, assisted by the RSAR drafting team or NPCC standards staff, until such time the RSC authorizes development of the standard. The Requester has the option at any time to allow the RSAR drafting team to assume full responsibility for the RSAR. The Requester may choose to participate in subsequent standard drafting efforts related to the RSAR.
- **Task Forces and Working Groups**,—The committees, task forces and working groups within NPCC , serve an active role in the standards process as follows:
 - Identify the need for new or modified regional standards.
 - Initiate NPCC Standards actions by developing Regional Standard Authorization Requests (RSARs).
 - Develop comments (views and objections) to standards actions.
 - Participate in NPCC Standard drafting.
 - Provide technical oversight in response to changing industry conditions and ERO Requirements.
 - Conduct Field Tests, as required
- **NPCC Compliance Committee (CC)**
 - Provide compliance review of technical requirements.
 - Assist the Drafting Team with the development of VSLs and VRFs.
 - Participate in a standard's quality review.
- **Compliance Monitoring and Enforcement Program** - The NERC Compliance Monitoring and Enforcement Program (CMEP) may be used to manage and enforce compliance with approved regional and NERC reliability standards. The compliance program area shall provide feedback to drafting teams during the standards development process to ensure the compliance enforcement program can be practically implemented for the standards under development.

The Compliance Monitoring and Enforcement Program may be used to conduct field tests or data collection related to compliance elements of proposed standards and may provide assistance with field tests or data collection when requested. The compliance enforcement program shares its observations regarding the need for new

or modified requirements with the standards staff for use in identifying the need for new standards projects.

- **Quality Review Team** - The Quality Review Team will be comprised of legal and compliance representatives, a technical writer, and NPCC Standards staff. It will not involve individuals who participated in the development of the standard.

4. PROCEDURE DESCRIPTION

COMMENT: The procedure does not address how someone requests the withdrawal of an existing standard or part thereof.

STEP 1 : REQUEST TO DEVELOP A NEW REGIONAL STANDARD

A Requester may request the development of a new Regional Reliability Standard or revision of an existing standard by submitting a Regional Standard Authorization Request (RSAR) form to the NPCC Manager of Reliability Standards, who will promptly acknowledge receipt. The RSAR is a description of the new or revised regional standard in sufficient detail to clearly define its scope, purpose, and importance, impacted parties and other relevant information. A “needs” statement will provide the justification for the development of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard. The Manager of Reliability Standards shall retain the RSAR form and make it available electronically on the NPCC Website.

The RSAR, as a minimum, shall contain the following information in order to be qualified for consideration. The NPCC Manager of Reliability Standards will assist the Requester to ensure all required information is submitted (on the RSAR):

1. Proposed Title and Date of New RSAR.
2. Requester’s Name and Contact Information.
3. Purpose of the Regional Standard.
4. Description of Industry Need.
5. Provide a Brief Description of the Standard.
6. Identification of the Entities in the Functional Model as being responsible to adhere to the standard.
7. Necessary information to assist the drafting the team, to the extent feasible, to allow them to draft the standard.
8. Any existing known cross references to NPCC or NERC documents.
9. Technical background for the RSAR to properly address the need for the standard.

In addition a Cost Benefit Analysis (CBA) for the proposed standard will be performed in accordance with the NPCC Cost Effectiveness Analysis Procedure (CEAP) and be made available for presentation with the RSAR to the RSC.

The Manager of Reliability Standards shall forward all properly completed RSARs and cost benefit information to the RSC. The RSC shall meet at established intervals to review all pending RSARs. The frequency of this review process will depend on workload, but in no case shall a properly completed RSAR wait for RSC action more than 60 calendar days from the date of receipt. The RSC may take one of the following actions:

- Remand the RSAR back to the Manager of Reliability Standards for additional work. In this case, the -Manager of Reliability Standards may request additional information or clarification for the RSAR from the Requester.
- Accept the RSAR as a candidate for a new or revised standard. The- Manager of Reliability Standards shall, within 60 calendar days of acceptance, post notification of intent to develop a standard on the NPCC Website, notify the ERO to post the notification on its Website, and notify the requester of the acceptance.
- Reject the RSAR. In this case, the RSC will provide its determination to the Manager of Reliability Standards, who will then provide a written explanation for rejection to the Requester within 60 calendar days of the rejection decision.

STEP 2: RSC ACCEPTS RSAR AND RCC ASSIGNS TF TO DRAFT NEW OR REVISED STANDARD

A RSAR that is accepted by the RSC shall be submitted to the RCC who shall assign the development of the regional standard to a Task Force within 60 calendar days. The Manager of Reliability Standards shall oversee solicitation and recommendation of a list of additional candidates for appointment to the Drafting Team, and shall submit the list to the RSC. This list shall include the Requester. The RSC may select other individuals to serve in drafting the Standard. The Drafting Team shall consist of a group of people who collectively have the necessary technical expertise and work process skills to effectively and efficiently produce a quality standard. ¶The Drafting Team reports to the RSC. The Drafting Team shall remain in place until such time as the NERC Board Of Trustees adopts the regional standard. Inquiries arising after a standard's development shall be directed by the RSC to the Task Force to which the drafting of the standard was assigned.

Concurrent with the formation of the Drafting Team, a technical group, or individuals may develop a first draft of the standard. This first draft ~~could~~ may be posted early in the standards development process for comment to gain industry insights and input early in the standards development process. Upon approval of Drafting Team members, any draft standards that have been developed by a technical group or individuals will be forwarded to the Chair of that team for use as a starting point in development of the standard. The Drafting Team will then assume ownership of the standard's drafting and responses to comments from initial postings prior to the Drafting Team's formation.

Comment: There needs to be closure by indicating when will the role of the technical group or individuals ends and the Drafting Team takes over. There may also be a need to indicate who is to respond to comments from the initial posting--not the technical group or individuals, but the DT.

~~The Manager of Reliability Standards shall serve, coordinate or assign~~ NPCC staff will to assist in the drafting of the standard including compliance measures, process and elements. The drafting of measures and compliance administration aspects of the standard will be coordinated with the NPCC Compliance Staff. When a drafting team begins its work, either in refining an RSAR or in developing or revising a proposed standard, the drafting team shall develop a project schedule and report its progress against that schedule to the RSC as requested, through the Manager of Reliability Standards.

Once the Drafting Team has produced a draft of the regional standard, VRFs, VSLs, variances and its associated implementation plan, NPCC standards staff shall coordinate Quality Review of the draft standard, consisting of technical writing, legal and compliance reviews prior to submission to RSC.

Implementation Plan

As a drafting team drafts its proposed revisions to a reliability standard, that team is also required to develop an implementation plan to identify any factors for consideration when approving the proposed effective date or dates for the associated standard or standards. As a minimum, the implementation plan shall include the following:

- The proposed effective date (the date entities shall be compliant) for the requirements.
- Identification of any new or modified definitions that are proposed for approval with the associated standard.
- Whether there are any prerequisite actions that need to be accomplished before entities are held responsible for compliance with one or more of the requirements.
- Whether approval of the proposed standard will necessitate any conforming changes to any already approved standards – and identification of those standards and requirements.
- The functional entities that will be required to comply with one or more requirements in the proposed standard.

A single implementation plan may be used for more than one standard. The implementation plan is posted along with the associated standard or standards for ballot. The Implementation Plan is posted for comment when available and prior to any ballots.

STEP 3: SOLICIT PUBLIC COMMENTS ON DRAFT REGIONAL STANDARD

Once a draft standard has been verified by the RSC to be within the scope and purpose of the RSAR, NPCC staff ~~the manager of Reliability Standards~~ will post the draft standard for the purpose of soliciting public comments. The posting of the draft standard will be linked to the RSAR for reference by its title. In addition to the standard, an implementation plan shall be posted to provide additional details to the public and aid in their commenting and decision process. This implementation plan will be drafted and posted with draft standards upon the availability of sufficient information, data or targeted survey results to determine a realistic schedule for implementation. Comments on the draft standard will be accepted for a 45 calendar day period from the public notice of posting. Comments will be accepted on-line using the NPCC Open Process web-based application. Supporting documentation such as VSLs, VRFs, Implementation Plans and Guidance documents will be posted as they become available with the draft standard postings.

Comment: Will VSL's and VRF's, Guidance Documents, etc. also be posted at this time? If not, why not, and when? Response: A draft standard does not necessarily need to include the VRFs and VSLs. A statement should be included to answer this question.

~~NPCC staff~~~~The manager of Reliability Standards~~ will notify NERC to concurrently post the draft standard and all associated documents= on the ERO Website for comments.

STEP 4: OPEN PROCESS POSTING AND ANALYSIS OF THE COMMENTS

The Manager of Reliability Standards= will assemble the comments on the new draft standard and associated documents and distribute those comments to the =Drafting Team. The Drafting Team shall give prompt consideration to the written views and comments of all participants. All submitted =comments shall be addressed, and each commenter shall be advised of the disposition of their comments and the reasons therefore. The Manager of Reliability Standards shall =publicly post all of the Drafting Team's responses to stakeholder comments on the NPCC Website.

The =Drafting Team shall take one of the following actions:

- Submit the draft standard for RCC endorsement as it stands, along with the comments received and responses to the comments. Based on the comments received, the Drafting Team may include revisions that are not substantive. A substantive change is one that directly and materially affects the application of the standard, including, for example: changing "shall" to "should," changing "should" to "shall"; adding, deleting, or revising requirements; or adding, deleting, or revising measures for which compliance is mandatory.
- Make substantive revisions to the draft standard and reposts it for further open review and comment.
- Drafting Team may recommends Field Testing if necessary, to the RSC.

~~Requester or =~~The RSC =may withdraw the request for the development of the regional standard at any time during the Regional Reliability Standards Process.

Comment: And then what happens? The RSC may want to continue with development of the standard and the Requester may want to appeal the decision not to proceed. No need to make any changes to the document, just answer the comment.

Upon receipt, the RCC submits the proposed regional standard to the RSC along with its recommendation=, Drafting Team statements and any field test results.

STEP 5: RSC APPROVES OF THE NEW OR REVISED STANDARD FOR POSTING

If the RSC, =utilizing the composite sector voting structure, = votes to post the draft regional standard for approval, the draft standard, all comments received, and the responses to those comments shall be posted publicly by the Manager of Reliability Standards on the NPCC Website (www.npcc.org) for a 30 calendar day "pre-ballot review" to be followed by a NPCC member approval ballot. If the RSC decides more work is needed, the draft standard will be remanded back to the Drafting Team. All actions of the RCC, Drafting Teams, and the RSC will be recorded in regular minutes of the group(s) and posted on the NPCC Website. Once the notice for a ballot has been issued, no substantive modifications may be made to the proposed standard unless the revisions are posted and a new notice of the vote is issued.

The Drafting Team, in coordination with the RSC, will determine when no further postings of the standard are required.

Prior to a “pre-ballot” review of a standard, a quality review and a cost effectiveness analysis will be ~~done~~ performed and submitted to the RSC for approval.

Comment: Who will do the cost effectiveness analysis? Who does the quality review?

Response: According to the CEAP. Quality Review will be done by NERC. Should we do it? Identify at what points the QR is done.

The Drafting Team working with CC members shall develop draft VSLs and VRFs prior to the quality review.

STEP 6: BALLOT OF STANDARD

Upon notification of a ballot, the Members of NPCC’s -ballot body will cast their vote consistent with the NPCC Bylaws. This ballot shall commence no sooner than 15 calendar days and no later than 30 calendar days following the notification of ballot. All members of the NPCC are eligible to participate in the voting on proposed, standard revisions or deletions of regional standards. The ballot period will typically begin immediately following the 30 calendar day pre-ballot posting and will last at least 10 business days.

In order for a NPCC Regional Standard to be approved;

- A quorum must be established by at least 50% of the NPCC Members of at least 60% of the Voting Sectors on the roster of Members maintained by NPCC.
- A two-thirds majority of the total weighted sector votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions, and non-responses. Weighted sector vote will be calculated as follows;
 - o Affirmative votes cast in each sector will be divided by the sum of affirmative and negative votes cast, in that same sector, to determine the fractional affirmative vote for each sector. Abstentions and non-responses will not be counted for the purposes of determining the fractional affirmative vote for a sector.
 - o The sum of the fractional affirmative votes from all sectors divided by the number of sectors voting will be used to determine if a two-thirds majority has been achieved. (A sector will be considered as “voting” if any member of the sector in the ballot pool casts either an affirmative or a negative vote.)
 - o A standard will be approved if the sum of fractional affirmative votes from all sectors divided by the number of voting sectors is at least 2/3.

Ballots will be cast electronically and alternatives are as follows;

- Affirmative
- Affirmative with Comments
- Negative
- Negative with Comments

- Abstain Comment: Could a member vote “Abstain”, yet still submit comments? To be investigated by GZ and LP. Comments should be allowed with the submission of an abstention.

The ~~Manager of Reliability Standards~~ shall post the final outcome of the ballot process. If the regional standard is ~~rejected~~ not approved, it may be withdrawn by either the RSC or the Requester, or the standard may be remanded by the RSC back to the Drafting Team to address the balloters’ comments. In the event the proposed regional standard is withdrawn all comments submitted during the process will be posted and archived for consideration when redrafting the standard ~~upon~~ under review.

Put in VSL straw poll process if we elect to go with it.

Once the member ballot approves the regional standard, the ~~Manager of Reliability Standards~~ Assistant Vice President-Standards shall ~~recommend~~ final Regional approval to the NPCC Board. The NPCC Board ~~Of Directors~~ may not make substantive modifications to the standard. If the NPCC Board of Directors does not approve the standard it will be remanded back to the RSC and the Drafting Team to address their concerns.

STEP 7: IMPLEMENTATION OF THE NPCC REGIONAL STANDARD

Upon approval by the NPCC BOD~~s~~, the Manager of Reliability Standards shall submit the regional standard ~~to the NERC/ERO for approval(s) and subsequent filing with FERC and applicable Canadian Governmental and/or Regulatory Authorities for adoption.~~

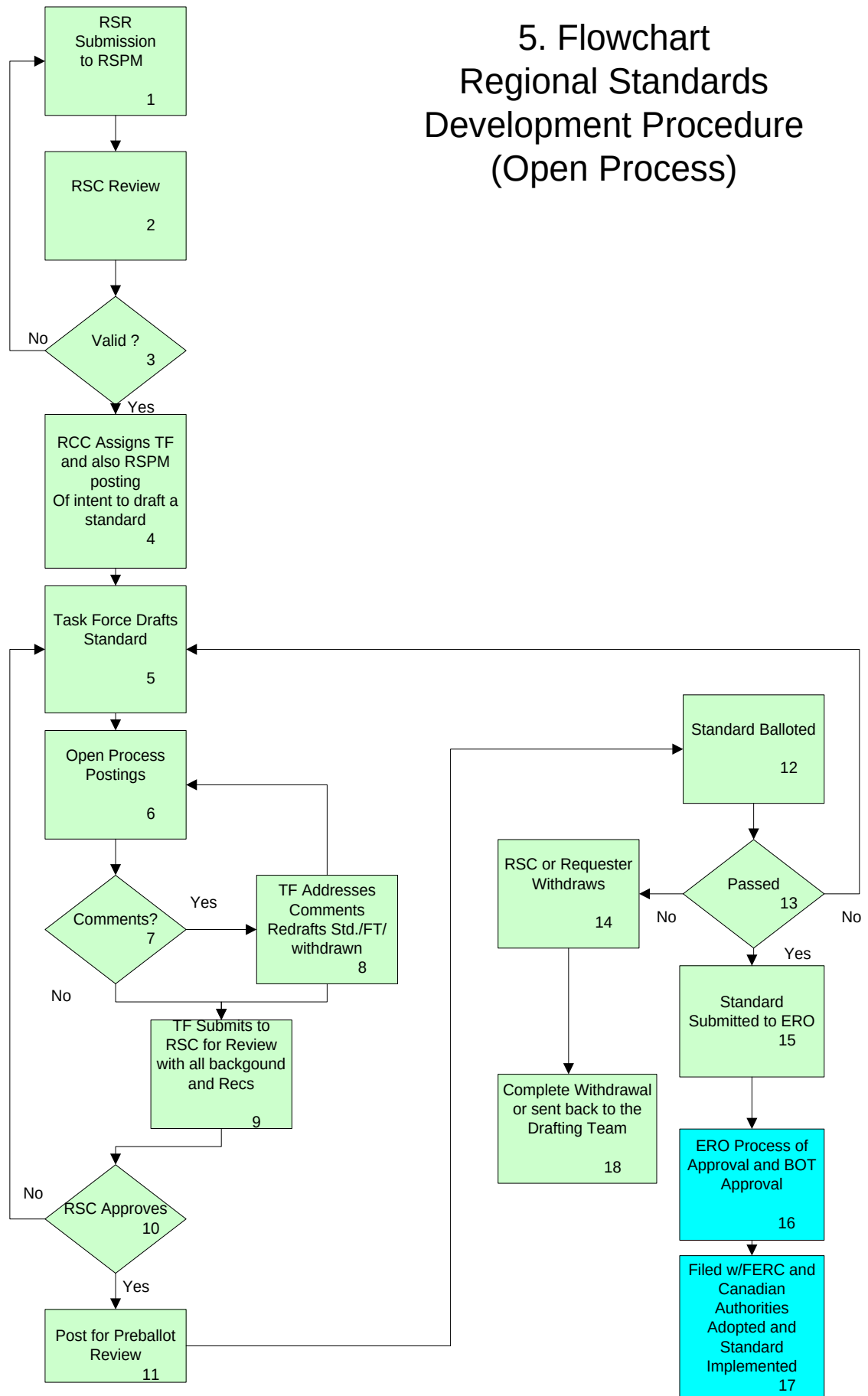
Once a reliability standard is adopted and made effective, all users, owners, planners, and operators of the Bulk Electric ~~System in the NPCC geographic area of the Northeast are required to comply with the standard.~~ The NERC/ERO Board of Trustees has established its ~~Compliance Monitoring and Enforcement Program~~ CMEP~~, administered in the Northeast by NPCC,~~ to measure compliance with reliability standards and administer sanctions as appropriate. After adoption of a NPCC Regional Standard, the standard will be included in the NERC/ERO CMEP~~Compliance Monitoring Enforcement Program.~~

STEP 8: WITHDRAWAL OR REMAND OF A REGIONAL STANDARD

The RSC may elect to withdraw the proposed standard or remand it back to the Drafting Team for further work for situations such as ballot failure, cost considerations, etc. (Comment: Should this be a specific, finite list of valid reasons for remand?) Response: A list will restrict the BOD. The Assistant Vice President-Standards will inform NERC and the industry of the actions taken.

The following flow chart will be revised for the final draft.

5. Flowchart Regional Standards Development Procedure (Open Process)



NPCC may need to develop a new or modified standard, VRFs, VSLs, definition, variance, or implementation plan under specific time constraints (such as to meet a time constrained regulatory directive) or to meet an urgent reliability issue such that there isn't sufficient time to follow all the steps in the normal standards development process. Under those conditions, the Standards Committee shall have the authority to approve any of the following actions to expedite development:

- Shorten the 45-day formal comment period
- Shorten the 30-day period for forming the ballot pool
- Allow significant modifications following the initial ballot without the need for another formal comment period provided the modifications are highlighted before conducting any successive ballot
- Shorten any of the 10-day ballot windows

If a new or modified standard is developed, approved by its ballot pool, and subsequently adopted by the NERC Board of Trustees through this expedited process, one of the following three actions shall occur²⁸:

- If the standard is to be made permanent without additional substantive changes, then a SAR and a proposed standard shall be submitted to the standards staff immediately after the ballot. The project shall be added to the list of approved projects and shall proceed through the regular standard development process, including balloting by stakeholders, without any intentional delay.
- If the standard is to be substantively revised or replaced by a new standard, then a project for the new or revised standard shall be added to the list of projects to be added to the Reliability Standard Development Plan. The project shall be initiated as soon as practical after the ballot and the project shall proceed through the regular standard development process, including balloting by stakeholders, as soon as practical but within two years of the date the standard was approved by stakeholders using the expedited process.
- The standard shall be withdrawn through a ballot of the stakeholders within two years of the date the standard was approved by stakeholders using the expedited process.

6. ERO and Regulatory Process and Approvals

- **NERC/ERO Comment Period** — Concurrent with regional posting of final drafts, the final drafts will be forwarded to NERC for posting on the NERC website to ensure full industry awareness of the standard and expedite and coordinate all commenting. NERC/ERO shall publicly notice and request comment on the NPCC ~~Regional Reliability~~ Standard and associated implementation plan, as specified by NERC- for comment on NERC's website and actively notify all adjoining Regions. =All comments will be responded to electronically by the Drafting Team through a posted response on the NPCC Website or a link on the NERC Website. NPCC shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the posting for comment; -revise the NPCC ~~Regional Reliability~~ Standard and request another posting for comments, or re-submit the NPCC ~~Regional Reliability~~ Standard along with a response to any objections received, for approval by NERC.

- **NERC/ERO Approval of NPCC Regional Reliability Standards** — Proposed regional reliability standards shall be subject to approval by the NERC/ERO who shall have a process to evaluate and recommend whether a proposed non-Interconnection-wide NPCC ~~R~~egional ~~R~~eliability ~~S~~tandard has been developed in accordance with all applicable procedural requirements and whether NPCC has considered and addressed stakeholder objections. NPCC BOD, having been notified of the results of the regional ballot concerning a NPCC ~~R~~egional ~~R~~eliability ~~S~~tandard, shall vote to submit the ~~S~~tandard to the NERC/ERO Board Of Trustees for approval as a NERC ~~R~~eliability ~~S~~tandard. The NERC/ERO Board Of Trustees shall consider NPCC's request, the scope and implications of the ~~S~~tandard, the recommendation for action on the ~~S~~tandard, any unresolved stakeholder comments, and NPCC's consideration of comments and unresolved issues, if any, in determining whether to approve the NPCC ~~R~~egional ~~R~~eliability ~~S~~tandard as a NERC ~~R~~eliability ~~S~~tandard.
- **Regulatory Authority Approval** — A NPCC ~~R~~egional ~~R~~eliability ~~S~~tandard that has been approved by the NERC/ERO Board Of Trustees shall be filed with FERC and applicable Canadian Governmental and/or Regulatory Authorities for approval and shall become effective and enforceable within the U.S., per Section 215 of the Federal Power Act, only when adopted by FERC in accordance with any associated implementation plan, and within individual Canadian Provinces, only when adopted by applicable Canadian Governmental and/or Regulatory Authorities in accordance with any associated implementation plan. The regional reliability standard, once adopted will be made part of the body of NERC reliability standards and shall be mandatory and enforceable on all applicable ~~B~~ulk ~~power~~Electric ~~S~~ystem owners, operators, and users within the NPCC Region in accordance with any associated implementation plan, regardless of membership status.

7. Appeals

- Persons who have directly and materially affected interests and who have been or will be adversely affected by any substantive or procedural action or inaction related to the -approval, revision, reaffirmation, or withdrawal of a regional reliability standard (appellant) shall have the right to appeal. This appeals process applies only to the regional reliability standards process as defined in this procedure.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within 30 calendar days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. In all cases, the request for appeal must be made prior to the next step in the process.

The final decisions of any appeal shall be documented in writing and made public.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants:

- Level 1 Appeal

Level 1 is the required first step in the appeals process. The appellant submits a complaint in writing to the Regional Standards Process Manager (RSPM) that describes the substantive or procedural action or inaction associated with a reliability standard or the standards process. The appellant describes in the complaint the actual or potential adverse impact to the appellant. Assisted by any necessary staff and committee resources, the RSPM shall prepare a written response addressed to the appellant as soon as practical, but not more than 45 calendar days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response will be made a part of the public record associated with the standard and posted with the standard.

- Level 2 Appeal

If after the Level 1 Appeal the appellant remains unsatisfied with the resolution, as indicated by the appellant in writing to the RSPM ~~Regional Standards Process Manager~~, the RSPM shall convene a Level 2 Appeals Panel. This panel shall consist of five members total appointed by the NPCC's Board of Directors.

In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The RSPM shall post the complaint and other relevant materials and provide at least 30 calendar days notice of the meeting of the Level 2 Appeals Panel. In addition to the appellant, any person that is directly and materially affected by the substantive or procedural action or inaction referenced in the complaint shall be heard by the panel. The panel shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal. The panel may in its decision find for the appellant and remand the issue to the RSC with a statement of the issues and facts in regard to which unfair and/or inequitable action was ~~not~~ taken, or which fair and/or equitable action was not taken. The panel may find for or against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections. The panel may not, however, revise, approve, disapprove, or adopt a reliability standard. The actions of the Level 2 Appeals Panel shall be publicly posted.

In addition to the foregoing, a procedural objection that has not been resolved may be submitted to the NPCC Board of Directors for consideration at the time the Board decides whether to adopt a particular reliability standard. The objection must be in writing, signed by an officer of the objecting entity, and contain a concise statement of the relief requested and a clear demonstration of the facts that justify that relief. The objection must be filed no later than 30 calendar days after the announcement of the vote on the standard in question.

Revision History

Version	NPCC Board Of Directors Approval	NERC Board Of Trustees Approval	FERC Approval
Original	9/19/07	10/23/07	3/21/08
Rev 1			

From: [Lee R. Pedowicz](#)
To: paul.difilippo@HydroOne.com
Cc: [Guy V. Zito](#); [Gerard J. Dunbar](#)
Subject: RSAR--PRC-002-NPCC-01 - Disturbance Monitoring
Date: Tuesday, April 17, 2012 9:26:00 AM

Good morning, Paul.

In my capacity as NPCC's Regional Standards Process Manager (RSPM), by this E-mail I hereby acknowledge receipt of your RSAR regarding proposed revisions to NPCC Regional Standard [PRC-002-NPCC-01 Disturbance Monitoring](#) to reflect the possible revision to the definition of the Bulk Electric System (BES) within NPCC. As per NPCC's [Regional Reliability Standards Development Procedure](#) I am returning the RSAR to you because it does not provide the necessary information to assist the drafting team to allow them to consider revising the Standard. That necessary information includes the technical justification supporting the development of a revised standard. PRC-002-NPCC-01 was written based on the information contained in NPCC's A-15 Criteria [Disturbance Monitoring Equipment Criteria](#), and the guiding parameters provided by system studies. Similar information is needed to substantiate a potential need for revision, and without that substantiation a potentially effective and efficient standard cannot be written.

In the [Industry Need](#) and [Detailed Description](#) sections of the RSAR reference is made to the redefinition of BES within NPCC. That redefinition has not been decided, and until that is formalized, work revising the Standard will not proceed. Work will not be done on the Standard based on speculation. The intent of the Standard is to ensure that adequate disturbance monitoring equipment is installed on the power system to capture information for detailed event analysis, and a redefinition of the BES should not hinder entities meeting the existing and FERC approved Standard's intent.

Lee Pedowicz
Manager, Reliability Standards
NPCC



1040 Avenue of the Americas - 10th Floor, New York, NY 10018-3703

NPCC RSC Triage Process for Standards Related Matters

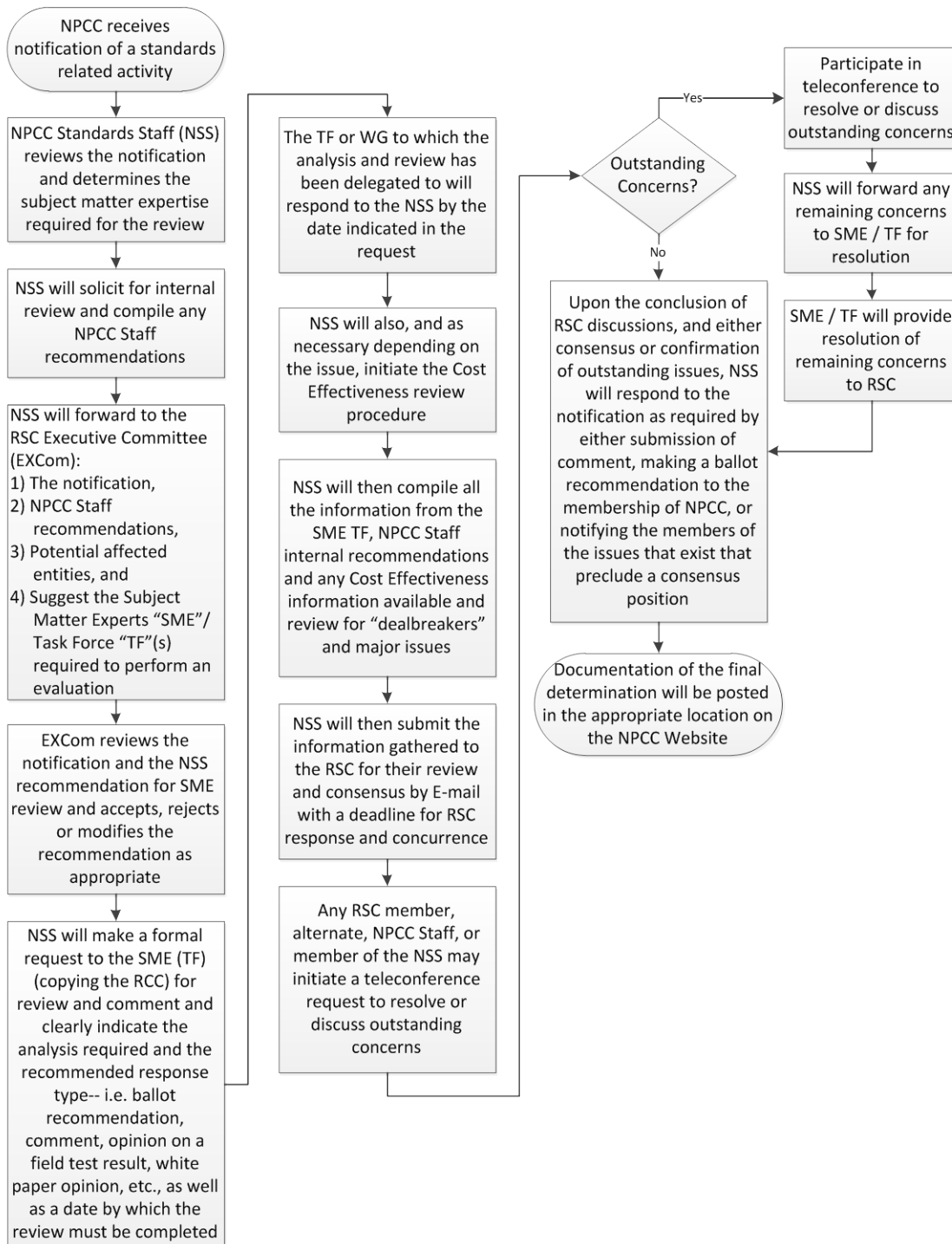
Objective: The NPCC RSC Triage Process is intended to be used to clearly identify the process that NPCC will utilize to evaluate continent-wide, regional standards and related matters. It is meant to ensure consistency, and that the proper resources are employed to review the technical subject matter and the proper policy level in order to ensure a sufficient review is done.

- 1) The Triage process will begin upon NPCC becoming aware of continent-wide or regional (NPCC, FRCC, etc.) standards related activity.
- 2) Because of the variability of deadlines for standards related activities, the NSS will develop a timeline for each activity to meet externally imposed "due dates".
- 3) NPCC Standards Staff (NSS) reviews the activity and determines the subject matter expertise required for the review.
- 4) NSS will solicit the appropriate NPCC Staff for an internal review and compile any NPCC Staff recommendations.
- 5) NSS will forward to the RSC Executive Committee (EXCom) the notification of the standards activity, NPCC Staff recommendations, potential affected entities, and suggest the Subject Matter Experts "SME" / Task Force "TF"(s) required to perform an evaluation.
- 6) EXCom reviews the notification and the NSS recommendation for SME review and appropriately accepts, rejects or modifies (including an alternate course of action) the recommendation.
- 7) NSS will make a formal request to the SME (TF) (copying the RCC) for review and comment and clearly indicate the analysis required and the recommended response type-- i.e. ballot recommendation, comment, opinion on a field test result, white paper opinion, etc., as well as a date by which the review must be completed. The TF or WG to which the analysis and review has been delegated to will respond to the NSS by the date indicated in the request.
- 8) NSS will also, and as necessary depending on the issue, discuss with the RSC the initiation of the Cost Effectiveness review procedure.
- 9) NSS will then compile all the information from the SME TF, NPCC Staff internal recommendations and any Cost Effectiveness information available and review for major issues and items or requirements that should prevent the activity from being continued.
- 10) NSS will then submit the information gathered to the RSC for their review and consensus.
- 11) Any RSC member, alternate, NPCC Staff (refer to Step 4 above), or member of the NSS may initiate a teleconference request to resolve or discuss outstanding concerns.
- 12) As necessary any remaining concerns will be brought to the SME/TF for resolution.
- 13) Upon the conclusion of RSC discussions, and either consensus or confirmation of outstanding issues, NSS will respond to the notification as required by either submission of comment,

making a ballot recommendation to the membership of NPCC, or notifying the members of the issues that exist that preclude a consensus position.

- 14) Documentation of the final response and supporting materials will be posted in the appropriate location on the NPCC Website.

NPCC RSC Triage Process for Standards Related Matters



From: [Gerard J. Dunbar](#)
To: [members-npcc-full](#)
Cc: [npcc-bod-2012](#); [rscmembers](#); [tfco-members](#); ["BoardSec@ontarioenergyboard.ca"](#); ["reliability_compliance"](#); [regulatory.affairs@ieso.ca](#); ["macd@ieso.ca"](#); ["Mike.yealland@ieso.ca"](#); [tina.teng@ieso.ca](#); [howard.gugel@nerc.net](#); [barbara.nutter@nerc.net](#)
Subject: Approval Ballot---NPCC Regional Reliability Directory #6 Reserve Sharing Groups
Date: Wednesday, March 14, 2012 4:24:59 PM
Attachments: [Directory 6 Reserve Sharing Groups Full Member Approval GJD March 13 2012.pdf](#)



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

March 14, 2012

NPCC Full Member Representatives and Alternates:

Subject: Approval Ballot for NPCC Regional Reliability Directory #6 Reserve Sharing Groups

Attached for your review and approval is NPCC Regional Reliability Directory#6 *Reserve Sharing Groups* which has been developed by the Task Force on Coordination of Operation (TFCO) and approved by the Reliability Coordinating Committee (RCC) at its meeting on March 1, 2012.

Directory #6 establishes requirements in the form of regional criteria to be used by NPCC Balancing Authorities (BAs) when participating in a Reserve Sharing Group (RSG).

Significantly, the Directory will require each RSG to estimate the change in reliability risk related to an individual agreement.

The Directory also sets forth specific requirements for the content of the agreements which will govern a RSG.

Directory#6 replaces NPCC Procedure C38 *Procedure for Operating Reserve Assistance* which was retired in 2010 upon the approval of NPCC Directory #5 *Reserve*.

This Directory has been developed in accordance with Phase 2 of the NPCC Directory project which is designed to promote the NPCC criteria in a results based format in order to demonstrate that the criteria is not inconsistent with ERO standards.

The TFCO has also established four new NPCC Glossary terms during the development of

Directory#6 all of which have been appended to the Directory for convenience; upon approval of Directory #6 and consistent with other NPCC Directories these terms will be removed from the Directory and included in the NPCC Glossary of Terms.

The development of Directory #6 was managed by the TFCO and it's Working Groups which posted the document to the NPCC Open Process.

In accordance with Section VIII of the NPCC Amended and Restated Bylaws dated April 15, 2011 this document will be considered approved upon receipt of a two- thirds weighted affirmative vote of the Full Members.

Your vote to approve this document signifies acceptance of:

- The NPCC Criteria governing Reserve Sharing Groups as contained in Directory #6 *Reserve Sharing Groups*

Please log in to the NPCC Website with your User ID and password and cast your vote electronically by April 6th, 2012.

<https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=109>

Please contact me with any questions regarding Directory content or voting instructions.

Thank you.

Gerry Dunbar
Northeast Power Coordinating Council, Inc.
212.840.1070 (p)
212.302.2782 (f)
gdunbar@npcc.org



NORTHEAST POWER COORDINATING COUNCIL, INC.
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NPCC
Regional Reliability Reference Directory # 6
Reserve Sharing Groups

Task Force on Coordination of Operations Revision Review Record:
April 06, 2012

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this April 06, 2012 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated April 15, 2011 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	April 6, 2012		New

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1.0 Title **Reserve Sharing Groups**

1.1 Directory Number 6

1.2 Objective

To provide the requirements for NPCC Balancing Authorities to participate in a **Reserve Sharing Group**.

1.3 Effective Date **April 6, 2012**

1.4 Background

This Directory was developed from the NPCC C-38 Procedure for Operating Reserve Assistance document.

1.5 Applicability

1.5.1 Functional Entities

- Balancing Authorities
- Reserve Sharing Groups

2.0 Terms Defined in this Directory

NPCC defined terms found in this Directory appear in bold typeface and can be found in the NPCC Glossary.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing requirements that are associated with this Directory include, but may not be limited to:

BAL-002

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

5.1 Reserve Sharing Group Requirements:

- R1.** The Balancing Authorities (BAs) participating in a **Reserve Sharing Group (RSG)** shall have a **RSG Agreement** that meets the requirements as specified in section 5.2.
- R2.** Each **RSG** shall provide their **RSG Agreement** to the Regional Entity for review before it is implemented.
 - R2.1** New **RSG Agreements** and future changes to existing **RSG Agreements** shall be approved by the Reliability Coordinating Committee (RCC).
- R3.** The Balancing Authorities (BAs) participating in a **Reserve Sharing Group (RSG)** shall be adjoining BAs unless they have a wheeling agreement with the intermediary BA or BAs.
- R4.** Each **RSG** shall provide the Regional Entity with a quantitative estimate of the change in reliability risk related to a reserve sharing agreement for review before their **RSG Agreement** is implemented.

There are a number of studies that could be performed to analyze the change in reliability risk such as:

- Megawatt Loss Probability Method
- Statistical analysis on the NPCC Area Trouble Report (ATR)/Simultaneous Activation of Reserve (SAR)Chronological event database
- Other comparable methods that produce the required reliability risk estimate.

5.2 Reserve Sharing Group Agreement Requirements:

- R5.** Each RSG Agreement shall specify the following:
 - R5.1** The BAs participating in the **RSG**.
 - R5.2** The BA acting as the Coordinator for the **RSG**.
 - R5.3** Intermediary BAs that have agreed to facilitate the transfer of **Reserve Sharing Group Energy (RSGE)** between non adjacent BAs in a **RSG**, through their BA Area without utilizing the **RSGE** or providing reserve for other BAs. Such BAs will be designated as a wheeling only BA and are not part of the **RSG**.

- R5.4** The effective date of the **RSG Agreement** and the renewal, review and termination dates if applicable.
- R5.5** The reserve product(s) being shared (e.g. ten minute, ten minute synchronized and thirty minute).
- R5.6** The minimum amount of each reserve product required by each of the participating BAs.
- R5.7** The conditions under which a participating BA will declare that they are unable to provide **RSGE**.
- R5.8** The method for determining **RSGE** share sizes for the participating BAs.
- R5.9** The conditions under which **RSGE** may be activated, including any time limits after a contingency occurs.
- R5.10** Details of how the activation and termination of **RSGE** are coordinated with Simultaneous Activation of Reserve Energy, other existing reserve activation agreements and other **RSGs**.
- R5.11** The ramp duration to be utilized for schedule changes when **RSGE** is activated and/or terminated.
- R5.12** The maximum duration for which the **RSGE** can be activated.
- R5.13** Times within which the **RSG Coordinator** shall:
 - Communicate changes in availability and deliverability of **RSGE** that are reported to it
 - Develop allocation shares if necessary
 - Specify schedule changes to activate **RSGE**
 - Adjust schedules to terminate the delivery of **RSGE**.
- R5.14** The communication method(s) to be used to exchange information with the **RSG Coordinator**.
- R5.15** The information that must be exchanged between the **RSG Coordinator** and participating BAs and between the **RSG Coordinator** and other **RSG Coordinators** and the **SAR Coordinator**.
- R5.16** Requirements for the payback of any delivered **RSGE**.
- R5.17** How transmission capability is utilized for planning and ensuring the availability and deliverability of **RSGE**.
- R5.18** The allocation between participating BAs, of any penalties resulting from the violation of NPCC or NERC criteria or standards.
- R5.19** **RSGE** shall meet the sustainability requirements specified in NPCC Directory 5 Reserve.

6. Compliance

6.1 Compliance Monitoring Process

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

Measures and corresponding Levels of Non Compliance for these requirements are contained within the compliance templates associated with this Directory.

6.2 Data Retention

Responsible Entities shall keep evidence of compliance for a minimum of three years. A Responsible Entity found non-compliant shall keep information related to the non-compliance until found compliant.

Lead Task Force: Task Force on Coordination of Operation

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments received in the Open Process, the Directory document will be sent to the RCC for approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References: *NPCC Glossary of Terms*
NPCC Directory #5 – Reserve

New NPCC Definitions Used in this Directory:

Reserve Sharing Group – A group comprised of two or more Balancing Authorities that share reserve in accordance with an approved Reserve Sharing Group Agreement.

Reserve Sharing Group Energy - Energy delivered to a contingent Balancing Authority from assisting Balancing Authorities that are part of the same Reserve Sharing Group.

RSG Coordinator – A Balancing Authority that accepted the role of **RSG Coordinator** in accordance with an approved **RSG Agreements**.

Reserve Sharing Group Agreement – An Agreement between members of a Reserve Sharing Group that meets the requirements of Directory #6 – Reserve Sharing Groups.

From: [Gerard J. Dunbar](#)
To: [members-npcc-full](#)
Cc: [npcc-bod-2012](#); [rscmembers](#); [tfco-members](#); [boardsec@ontarioenergyboard.ca](#); [program@ieso.ca](#); [regulatory.affairs@ieso.ca](#); [macd@ieso.ca](#); ["Mike.yealland@ieso.ca"](#); [tina.teng@ieso.ca](#); [howard.gugel@nerc.net](#); [barbara.nutter@nerc.net](#)
Subject: NPCC Directory #6 Reserve Sharing Groups - Approved
Date: Monday, April 09, 2012 3:57:32 PM
Attachments: [Directory 6 Reserve Sharing Groups Full Member Approved GJD April 6, 2012.pdf](#)



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

April 9th, 2012

NPCC Full Member Representatives and Alternates:

Subject: NPCC Regional Reliability Directory #6 Reserve Sharing Groups:

On April 6, 2012 the NPCC Full Member Committee approved *Directory #6 Reserve Sharing Groups*.

Directory#6 was developed in order to establish requirements in the form of regional criteria which will be used by NPCC Reliability Coordinators (RC's) when participating in a Reserve Sharing Group (RSG).

The development of Directory#6 was managed by the *Task Force on Coordination of Operation* (TFCO) and requires each RSG to estimate the change in reliability risk related to an individual agreement.

The Directory also sets forth specific requirements for the content of the agreements governing each RSG.

Directory#6 was developed in accordance with Phase 2 of the NPCC Directory project which is designed to promote the NPCC criteria in a results based format in order to demonstrate that the criteria is not inconsistent with the ERO standards.

A copy of the document as well as the final Member vote count may be found at:

<https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx>

Respectfully,

Gerry Dunbar
Northeast Power Coordinating Council, Inc.
212.840.1070 (p)
212.302.2782 (f)
gdunbar@npcc.org

From: [Gerard J. Dunbar](#)
To: [Guy V. Zito](#)
Cc: [Lee R. Pedowicz](#)
Subject: TFCP
Date: Tuesday, April 17, 2012 4:04:37 PM

Guy....I participated on the TFCP conference call this afternoon since the status of D#1 was on their agenda...

- TFCP also received a report from National Grid as a follow up to the RCC A10 discussion in March.....RCC expressed concern over the frequent use of the request for waiver of the A10 implementation plan among NPCC Full Members.....National Grid reported to TFCP that as a result of revisiting design and outage considerations they were withdrawing their waiver requests at two stations (Porter in NY...and DuPont in Mass.).....in both cases Natl. Grid withdrew the waiver request and provided TFCP with expected compliance dates that were earlier than the dates submitted to RCC.....National Grid did submit a request for an extension of the waiver for one station in Mass. (Auburn St.) but was able to move up the expected compliance date from what was originally submitted to RCC in March.
- TFCP is still struggling with D#1.....the issue is different than TFCO's.....has to do with the use of 10 minute and 30 Minute reserve in clearing N-1 planning contingencies.....they agreed to devote most of their next meeting on May 9th to addressing the issue....I was able to provide them with an update on the TFCO schedule for addressing D#1....TFCO is devoting a full day to D#1 on May 16th in Syracuse to try and get D#1 finished and back to TFCP....Pat Doran is supposed to do the drafting work on the Transmission Operating criteria in advance of that meeting but I don't think Jerry has executed the contract with him yet.....I plan on attending the TFCO meeting in Syracuse....May 16th and 17th.....

Gerry Dunbar
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Directory Work Plan for Phase 2 Reformatting

April 2012

Directory Number Title	Criteria document and Title	Lead Task Force	Last Update	Next Update	Comments	Status	Notes
Directory #1 Design and Operation of the Bulk Power System	(A2) Basic Criteria for Design and Operation of Interconnected Power Systems	TFCP	Dec-09	Under Review	Phase 2 draft developed. TFCP coordinating TFSS and TFCO comments on document.....TFCO reviewing Operating Criteria.....TFCP (CP11) reviewing N-1 criteria.	Initial Open Process posting expected mid-2012.	
Directory #2 Emergency Operations	(A3) Emergency Operation Criteria	TFCO	Oct-08	TBD			TFCO to Establish Phase 2 Priority among D2, D5, and D8.
Directory #3 Maintenance Criteria for Bulk Power System Protection	(A4) Maintenance Criteria for Bulk Power System Protection	TFSP	Jul-08	TBD	Review of D#3 Pending Development of PRC-005.	Phase 2 to Commence Upon Approval of PRC - 005.	TFSP to Establish Phase2 Priority between D3 and D4.
Directory #4 Bulk Power System Protection Criteria	(A5) Bulk Power System Protection Criteria	TFSP	Dec. 09	TBD	TFSP Completed Review of D#4 in December 2009.	Phase 2 to Commence in 2012.	TFSP to Establish Phase 2 Priority between D3 and D4.
Directory #5 Reserve	(A6) Operating Reserve Criteria	TFCO	Dec-10	Under Review	TFCO Addressing RCC Reserve Issues in Phase 1 format. TFCO Anticipates Posting D#5 for Comment mid 2012.		TFCO to Establish Phase 2 Priority among D2, D5 and D8.
Directory #6 Reserve Sharing	(New) RRSE C38	TFCO	New	New	NPCC Full Members approved new Directory#6 in Phase 2 format on April 6, 2012.	Phase 2 Complete.	
Directory #7 Special Protection Systems	(A11) Special Protection System Criteria	TFSP	Dec-07	Under Review	TFSP Coordinating Review of D#7 (Appendix A) Review with TFCP and TFSS. Phase 2 Draft Provided to TFSP	TFSP Preparing Phase 2 Draft for Open Process pending resolution of Compliance issue associated with D#4 and D#7.	
Directory #8 System Restoration	(A12) System Restoration Criteria	TFCO	Oct.-10.	Spring 2012	TFCO Working Group CO11 to review initial Phase 2 Draft of D#8 IN May 2012.	CO11 will incorporate recent revisions into Phase 2 draft.	TFCO to Establish Phase 2 Priority among D2, D5 and D8.
Directory #9 Verification of Generator Gross and Net Real Power Capability	(A13) Verification of Generator Gross and Net Real Power Capability	TFCO/TFCP			NPCC Full Members approved Phase 2 Version of Directory#9 on December 28, 2011.	Phase 2 complete.	
Directory #10 Verification of Generator Gross and Net Reactive Power Capability	(A14) Verification of Generator Gross and Net Reactive Power Capability	TFCO/TFCP			NPCC Full Members approved Phase 2 Version of Directory#10 on December 28, 2011.	Phase 2 complete.	
Directory #12 Underfrequency Load Shedding Program Requirements	SS-38 Study Report on 2006 Assessment of Underfrequency Load Shedding Adequacy	TFSS	Jun-09	Jun-12	Regional Standard on UFLS approved by NPCC BOD and NERC BOT.....submitted to FERC for approval April 16th, 2012.	Directory #12 will be retired upon FERC and Provincial approvals.	



Monthly NERC, NAESB, Regional Entity Update

Creating a Culture of Compliance

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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
4/6/12	Opening of Initial Ballot Window for Project 2010-07: Generator Requirements at the Transmission Interface	NERC
4/9/12	Close of Formal Comment Period for Project 2010-07: Generator Requirements at the Transmission Interface	NERC
4/9/12	Close of Successive Ballot Window for Project 2010-07: Generator Requirements at the Transmission Interface	NERC
4/11/12	Opening of Ballot Window (Three Successive Ballots and Two Non-binding Polls) for Project 2007-03: Real-Time Transmission Operations	NERC
4/15/12	Data Submittal - BAL-001-0- Real Power Balancing Control Performance (CPS 1 & CPS 2): March, 2012	RFC
4/15/12	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – March, 2012	RFC/ NERC
4/15/12	Data Submittal – BAL-002-0 Disturbance Control Performance	RFC
4/16/12	Close of Formal Comment Period for Project 2010-07: Generator Requirements at the Transmission Interface	NERC
4/16/12	Close of Initial Ballot Window for Project 2010-07: Generator Requirements at the Transmission Interface	NERC
4/16/12	Close of Ballot Window for Three Ballots and Three Non-binding Polls for Project 2007-09 Generator Verification (PRC-019-1, MOD-025-2 & MOD-027-1)	
4/16/12	Close of Formal Comment Period for Project 2007-09 Generator Verification (PRC-019-1, MOD-025-2 & MOD-027-1)	NERC
4/20/12	Close of Ballot Window (Three Successive Ballots and Two Non-binding Polls) for Project 2007-03: Real-Time Transmission Operations	NERC
4/20/12	Close of Formal Comment Period for Project 2007-03: Real-Time Transmission Operations	NERC

FERC

FERC Orders of Note

March 1, 2012

[Order on Notices of Penalty – January 31/February 1, 2012](#)

[Notices of Penalty](#)

[Letter Order Restoring Section 402.1.3.2 of NERC ROP](#)

Docket No. RR10-11-004

March 15, 2012

[Order No. 759 – Approving Transmission Relay Loadability Reliability Standard PRC-023-2](#) Docket No. RM11-16-000

[Order Accepting with Conditions Petition Requesting Approval of New Enforcement Mechanisms and Requiring Compliance Filing](#) Docket Nos. RC11-6-000, RC12-1-000, RC12-2-000, RC12-6-000, RC12-7-000 and RC12-8-000

March 30, 2012

[Order on Notices of Penalty - February 29, 2012 Notices of Penalty](#)

NERC Filings to FERC

[Informational Filing of NERC in Response to Order No. 754](#)

Docket No. RM10-6-000

March 16, 2012

[Errata to NERC Glossary of Terms Definition of IROL](#) Docket

No. RM06-16-000

March 23, 2012

[Comments in Response to Notice of Proposed Rulemaking on Standard for Business Practices for Interstate Natural Gas Pipelines](#) Docket No. RM96-1-037

March 30, 2012

[Motion for an Extension of Time](#) Docket No. RM06-16-000

[Comments of NERC on the Coordination Between Natural Gas and Electricity Markets](#) Docket No. AD12-12-000

[NERC 2012 Standards Report, Status, and Timetable for Addressing Regulatory Directives](#) Docket No RR12-_-__

March 15, 2012

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 2010-07 – Generator Requirements at the Transmission Interface – FAC-003-x, FAC-003-3	Successive Ballots	03/30/12	04/09/12
Project 2007-09 – Generator Verification - MOD-025-2, MOD-027-1 and PRC-019-1	Initial Ballots and Non-binding Polls	04/06/12	04/16/12
Project 2010-07 – Generator Requirements at the Transmission Interface - PRC-005-1.1a	Initial Ballot	04/06/12	04/16/12
Project 2007-03 – Real-time Transmission Operations – TOP-001 through TOP-008 and PER-001	Successive Ballots	04/11/12	04/20/12
Join Ballot Pools (Ballot Pool Windows Close at 8 a.m. Eastern)			
Project 2010-07 – Generator Requirements at the Transmission Interface - PRC-005-1.1a	Join	03/02/12	03/31/12
Posted for Comment (Closes at 8 p.m. Eastern) (Sorted by End Date)			
Project 2010-07 – Generator Requirements at the Transmission Interface - FAC-003-x, FAC-003-3	Comment Form	03/09/12	04/09/12
Project 2007-09 – Generator Verification - MOD-025-2, MOD-027-1 and PRC-019-1	Comment Form	02/29/12	04/16/12
Project 2010-07 – Generator Requirements at the Transmission Interface - PRC-005-1.1a	Comment Form	03/02/12	04/16/12
Project 2007-03 – Real-time Transmission Operations – TOP-001 through TOP-008 and PER-001	Comment Form	03/22/12	04/20/12

**NERC
Ballot Results**

See more information on the NERC [Ballot Results web page](#)

Initial Ballot Results

- Project 2011-INT-02 Rapid Revision of VAR-002 for Constellation

Voting statistics are listed below:

Quorum: 86.92%

Approval: 63.09%

The drafting team will consider all comments submitted, and based on the comments will determine whether to make additional changes.

- Project 2009-26 Interpretation of CIP-004-x for WECC

Voting statistics are listed below:

Quorum: 88.55%

Approval: 79.61%

The CIP Interpretation Drafting Team will consider all comments submitted, and based on the comments will determine whether to make additional changes.

- Project 2010-INT-05 Interpretation of CIP-002-x for Duke

Voting statistics are listed below:

Quorum: 89.63%

Approval: 94.71%

The CIP Interpretation Drafting Team will consider all comments submitted, and based on the comments will determine whether to make additional changes.

Recirculation Ballot Results

- None

Successive Ballot Results

- None

Final Ballot Results

- None

NERC Miscellaneous News

- NAESB and OATI announced that the new electric industry registry, webRegistry (formerly the Transmission System Information Network), is open for registration. More information can be found [here](#).
- Draft minutes and presentations from the March Critical Infrastructure Protection Committee have been posted, and can be found [here](#).
- NERC completed its after-action review of the 2011 grid security exercise, GridEx 2011. The review identifies key findings and recommendations for improving the electric industry's cybersecurity programs. The full report can be found [here](#).
- Three new lessons learned have been posted on the NERC website, and can be found [here](#).
- The March 2012 NERC Newsletter can be found [here](#).

REGIONAL ENTITIES

ReliabilityFirst

- The March RFC Newsletter can be found [here](#).
- RFC CMEP Update



2012 RFC Compliance
Monitoring Schedule

Midwest Reliability Organization (MRO)

- Find the March/April 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****NAESB membership ratified:**

- Interpretation - C11004: Clarify WEQ-001-9.1 and WEQ 001-10.1 can support a modification of only the source or sink for a long-term firm reservation
- Standards Recommendations -
- 2012 Wholesale Electric Annual Plan Item No. 5.e – Supporting Crediting Redirect Requests with the Capacity of the Parent Reservation Recommendation)
- 2012 WEQ Annual Plan Item 1.d – Revised Bulk Electric System Definition Recommendation

Electric Industry Registry

- Early registration began on March 20th for Reliability Coordinations
General entity registration began on March 28

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

April 2012						
Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
						1
2	3	4	5	6	7	8
9	10 NERC Webinar Project 2008-06 Cyber Security 1:00 – 4:00 PM	11 RFC WebCDMS Training 2:00 – 4:00 PM	12	13	14	15
16 NERC Compliance Workshop	17 NERC Compliance Workshop	18 NERC Compliance Workshop	19	20	21	22
23	24	25	26	27	28	29
30						

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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Due Date	Deliverable	Entity
5/3/12	Close of Recirculation Ballot Window for Project 2010-07: Generator Requirements at the Transmission Interface	NERC
5/7/12	Close of Comment Period for Draft CANs CIP-007, CIP-005, EOP-002 and PER-002	NERC
5/15/12	Data Submittal - BAL-001-0- Real Power Balancing Control Performance (CPS 1 & CPS 2): April, 2012	RFC
5/15/12	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – April, 2012	RFC/ NERC
5/15/12	Opening of Successive Ballot and Non-binding Poll for Project 2009-01: Disturbance and Sabotage Reporting	NERC
5/21/12	Close of Formal Comment Period for Ten Standards, Implementation Plan and Definitions for Project 2008-06: Cyber Security Order 706 Version 5 CIP	NERC
5/24/12	Close of Formal Comment Period for Project 2009-01: Disturbance and Sabotage Reporting	NERC
5/24/12	Close of Successive Ballot and Non-binding Poll for Project 2009-01: Disturbance and Sabotage Reporting	NERC
6/15/12	Data Submittal - BAL-001-0- Real Power Balancing Control Performance (CPS 1 & CPS 2): May, 2012	RFC
6/15/12	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – May, 2012	RFC/ NERC
6/25/12	Close of Comment Period for “Adequate Level of Reliability” Revised Definition and Associated Documents	NERC

FERC

FERC Orders of Note

April 19, 2012

[Order No. 761 – Final Rule Approving Version 4 CIP Standards](#) Docket No. RM11-11-000 (Order No. 761)

[NOPR Proposing to Remand TPL-001-2](#) Docket No. RM12-1-000

[Order No. 762 – Final Rule Remanding TPL-002-0b](#) Docket No. RM11-18

[Order Granting Appeal of an ERO Compliance Registry Determination and Remanding for Further Proceeding](#) Docket No. RC08-5-001

[Order Denying Appeal of an ERO Compliance Registry Determination](#) Docket No. RC11-5-000

[NOPR on Standards for Business Practices and Communication Protocols for Public Utilities](#) Docket No. RM05-5-020

[Notice of Inquiry on Open Access and Priority Rights for Capacity on Interconnection Facilities](#) Docket No. AD11-11-000

April 23, 2012

[Notice Inviting Comments on Report Prepared by PNNL on “Applicability of the ‘Gallet Equation’ to the Vegetation Clearances of NERC Reliability Standard FAC-003-2”](#) Docket No. RM12-4-000

April 27, 2012

[Order on Notices of Penalty – March 30, 2012 Notices of Penalty](#)

NERC Filings to FERC

April 12, 2012

[Informational Filing in Response to FERC Order No. 758 – Interpretation of Protection System Reliability Standard](#) Docket No. RM10-5-000

April 16, 2012

[Limited Request for Clarification, or, in the Alternative Rehearing of the March 15, 2012 FFT Order](#) Docket No. RC11-6-001

April 24, 2012

[Errata to Petition for Approval of FAC-003-2](#) Docket No. RM12-4-000

April 27, 2012

[Errata to Petition for Approval of Proposed Texas Regional Entity Reliability Standard IRO-006-TRE-1](#) Docket No. RD12-1-000

April 30, 2012

[Informational Report of NERC on Analysis of Standards Process Results for the First Quarter 2012](#) 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)	Successive Ballots	05/11/12	05/21/12
Project 2009-26 — Interpretation of CIP-004-1 for WECC	Recirculation Ballot	04/20/12	04/30/12
Interpretation 2010-INT-05 — Interpretation of CIP-002-1 R3 for Duke Energy	Recirculation Ballot	04/20/12	04/30/12
Project 2010-07 — Generator Requirements at the Transmission Interface — FAC-003-x, FAC-003-3, PRC-005-1.1a	Recirculation Ballots	04/24/12	05/03/12
Project 2007-03 — Real-time Transmission Operations — TOP-001 through TOP-008 and PER-001	Recirculation Ballots	04/27/12	05/06/12
 Project 2009-01 — Disturbance and Sabotage Reporting — CIP-001 and EOP-004	Successive Ballot and Non-binding Poll	05/15/12	05/24/12
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 A: CIP-002 and CIP-003 Comment Form B: CIP-004 through CIP-007 Comment Form C: CIP-008 through CIP-011 Comment Form D: Definitions and Implementation Plans	04/12/12	05/21/12
 Project 2009-01 — Disturbance and Sabotage Reporting — CIP-001 and EOP-004	Comment Form	04/25/12	05/24/12

**NERC
Ballot Results**

See more information on the NERC [Ballot Results web page](#)

Initial Ballot Results

- Project 2007-09 Generator Verification

Voting statistics are listed below:

MOD-025-2

Quorum: 88.28%

Approval: 41.09%

MOD-027-1

Quorum: 88.04%

Approval: 36.84%

PRC-019-1

Quorum: 88.04%

Approval: 48.70%

The drafting team will consider all comments submitted, and based on the comments will determine whether to make additional changes.

- Project 2010-07 Generator Requirements at the Transmission Interface

Voting statistics are listed below:

Quorum: 88.95%

Approval: 92.41%

The drafting team will consider all comments submitted, and based on the comments will determine whether to make additional changes.

Recirculation Ballot Results

- Project 2007-03 Real-time Operations

Voting statistics are listed below:

TOP-001-2

Quorum: 78.28%

Approval: 75.65%

TOP-002-3

Quorum: 78.02%

Approval: 87.22%

TOP-003-2

Quorum: 78.28%

Approval: 80.11%

The Drafting Team will consider all comments submitted, and based on the comments will determine whether to make additional changes.

Successive Ballot Results

- None

Final Ballot Results

- None

NERC Miscellaneous News

- NERC, EPRI Release Open Source Code to Analyze Geomagnetically Induced Currents. The full story can be found [here](#).
- The slides and Q & A from the March 15, 2012 ERO Event Analysis Process Webinar have been posted [here](#).
- The Q & A from the March 20, 2012 FAC Alert Recommendation Update webinar have been posted [here](#).
- Three new lessons learned have been posted on the NERC website, and can be found [here](#)
- The March 2012 NERC Newsletter can be found [here](#).

REGIONAL ENTITIES

ReliabilityFirst

- The April RFC Newsletter can be found [here](#).
- RFC CMEP Update



2012 RFC Compliance
Monitoring Schedule

Midwest Reliability Organization (MRO)

- Find the March/April edition of the MRO Midwest Reliability Matters Newsletter [Here](#).
- Find the MRO Standards page [here](#).
- Find the MRO Compliance page [here](#).

SERC

- The 2013 SERC Draft Business Plan and Budget has been posted [here](#).
- See the latest SERC news [here](#).
- Find the SERC Standards page [here](#).

NAESB**Recent NAESB Activity**

NAESB has posted links to a number of documents on the Electric Industry Registry Webpage. There are Quick Start Guides for the different user roles, a User Guide, a Technical Guide and a General Quick Start Guide. These documents can be found at the [NAESB Website](#).

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

May 2012						
Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
	1 NERC Webinar – Member Representatives Committee 11:00 AM – 1:00 PM	2	3 NERC Webinar Draft 2013 Business Plan and Budget 10:00 AM	4	5	6
7	8 NERC – Finance and Audit Committee Meeting 10:00 AM	9	10	11	12	13
14	15	16	17	18	19	20
21	22 Project 2007-12 Frequency Response Technical Conference Arlington, VA	23	24 Project 2007-12 Frequency Response Technical Conference Denver, CO	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

Draft

2012 NERC Corporate Performance Measures

For Board Approval February 23, 2012

During the last few years, NERC has been improving its process for measuring corporate and department performance against goals, objectives, and pre-established metrics. Incentive compensation for all NERC officers and employees is now tied to these yearend corporate and department results, as well as to individual performance assessments. NERC has most recently adopted internal tools for measuring individual performance to include electronic tracking of corporate and department results in 2012. Weighting among the corporate, department and individual components varies, depending on level of seniority in the company.

Management has continued to improve the performance metrics each year, first by reducing them to a smaller number of more important metrics. In addition, the substance of the metrics has shifted toward results that improve reliability and less on counting the numbers of NERC activities performed. The challenge remains to define metrics that are within NERC's span of influence or control while encompassing meaningful results related to bulk power system reliability performance and effective risk mitigation strategies. Based on discussions with the Trustees at the February 7-9, 2012 meetings, NERC is introducing for the first time during 2012 a performance metric based on overall reliability performance: *10% of at-risk compensation will depend on experiencing no Category 5 events (loss of greater than 10,000 MW of load or generation excluding those caused by natural disaster)*. The metrics have also been restated as Target at 100% payout and Threshold at 70%, with no credit for less than Threshold achievement.

NERC has collaborated with the eight Regional Entities to create a common strategic planning framework, the **Electric Reliability Organization Enterprise Strategic Plan 2012-2015**. This plan has evolved from the strategic plan that was reviewed by the NERC board in February 2011. The updated version of the Strategic Plan is being used by NERC and the Regional Entities as they formulate business plans and budgets for the coming year. For 2012, NERC is presenting its corporate performance measures using the framework provided by the ERO Enterprise Strategic Plan, spanning goals in three areas: 1) standards and compliance; 2) risks to reliability; and 3) coordination and collaboration.

The specific measures presented below were derived from goals and objectives outlined in the **2012 NERC Business Plan and Budget**, which was approved by the NERC board on August 4, 2011 and accepted by the Federal Energy Regulatory Commission in its order issued October 20, 2011. The strategic plan from February 2011 was an additional resource.

The Corporate Governance and Human Resources Committee reviewed the measures and provided inputs on February 7-8, 2012. The board is requested to approve the final revised 2012 metrics by conference call on February 23, 2012.

2012 NERC Corporate Performance Measures – Draft for Board Approval February 23, 2012

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.

	Objective	Measure	Threshold	Target	Weight
1.	Develop a technically sufficient set of results-based reliability standards, with each requirement providing a clearly and unambiguously identified performance expectation and reliability benefit.	Number of new, or substantively revised standards delivered for board approval, excluding retirements	12 standards	16 standards	8%
2.	Be accountable to applicable regulatory authorities and the public for standards that provide an adequate level of reliability.	Reduction (in percent) of standards-related directives remaining compared to 260 directives at 2012 year beginning, including any new directives issued	20% reduction to 208	30% reduction to 182	2%
3.	Working with industry, develop options to improve the efficiency and timeliness of standards development such that high priority standards may be targeted for completion in one year.	Process revisions that meet the one year criterion	Drafted for public comment	Revisions complete and ready for board approval by yearend	5%
4.	Work with industry to develop technical references or application guides for reliability standards to ensure clarity and facilitate implementation.	Develop plan a) listing priorities based on risk and clarity gap, and b) identifying formats and procedures (use existing formats as appropriate such as RSAWs,	Plan and templates developed	Application guides or technical references delivered for 10 standards	3%

		regional entity application guides, standards references, CANs, etc.)			
5.	Develop a robust set of critical infrastructure reliability standards that enable industry to adapt to continuously changing threats and vulnerabilities by emphasizing security risk management.	Complete the CIP Version 5 standards (or equivalent) by yearend 2012	Approved by industry through successive ballot	Approved by industry through recirculation ballot and ready for board approval	5%

- 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.

	Objective	Measure	Threshold	Target	Weight
6.	Continue to develop enhancements to enforcement processing to achieve efficient and timely compliance outcomes, including streamlined procedures for lesser risk violations and improved workflow and tools at NERC and regional entities. Explore alternatives to refining discretion focused on targeting violations most implicated in large events. Further develop FFT enhancements, spreadsheet NOPs, and other efficiencies and options for exercising discretion for lesser risk violations.	Average process duration for lesser risk violations filed in 2012 from discovery to filing, excluding those with discovery dates preceding July 1, 2011	6 months	4.5 months	2%
		Average process duration for greater risk violations from discovery to filing, excluding those with discovery dates preceding July 1, 2011	12 months	10 months	2%
		Yearend six-month rolling average of total FFT and spread-sheet NOPs filed monthly as a percent of active violations	4%	6%	2%
7.	Reduce NERC/RE caseload index (proxy for how many months work remain in caseload).	Six-month rolling average of active violations divided by monthly filings and dismissals	18 months	12 months	3%

8.	Close outstanding enforcement cases with violation dates from 2007 – 2010.	Number of cases remaining unfiled with violation date preceding January 1, 2011	75% reduction, excluding those held by proceedings at FERC or court	Zero left, excluding those held by proceedings at FERC or court	2%
9.	Identify nature of violations associated with most significant system events and develop a plan for addressing risks in these areas.	Report on requirements most correlated to significant events (Category 3 and above) and plan for addressing risks	Report on risks correlated to significant events	Report on risk control strategies to address top 3 issues identified	2%

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.

	Objective	Measure	Threshold	Target	Weight
10.	Develop a program to allow compliance trials following NERC board approval of reliability standards, for the purpose of allowing industry to come into compliance and mitigate compliance risk while the ERO validates compliance measures and procedures, minimizing inefficiencies and detrimental effects of learning through enforcement.	Develop report outlining process and instruments to be used, and identifying candidate standards for demonstration	Report published	Pilot initiated for 1 new standard	3%
11.	Educate industry on effective compliance programs and effective reliability risk controls.	Identify and document case studies of entities with exemplary compliance risk and reliability risk controls	1 large entity and 1 small entity	1 additional case study	2%
		Continue CIP-002 Sufficiency Review Program (SRP) to evaluate entities' Critical Assets and Critical Cyber Assets lists	Conduct 6 SRPs	Conduct 10 SRPs	1%

12.	Develop risk-based compliance monitoring approaches to maximize reliability benefits and improve efficiencies, and to encourage effective internal controls at registered entities.	Identify and assess through pilot testing alternative risk-based approaches to monitoring compliance, including use of sampling methods	Report on alternative approaches for monitoring compliance	Complete three pilot tests to demonstrate methods	3%

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.

	Objective	Measure	Threshold	Target	Weight
13.	Trend reliability issues and improvement opportunities and share results transparently with bulk power system owners, operators, and users.	Report on state of reliability identifies risk clusters and trends	Report delivered by Q3	Report completed by Q2	3%
14.	Provide an event analysis program that engages bulk power system owners, operators, and users in determining root causes, lessons learned, and other improvement opportunities; ensure all events meeting criteria are catalogued, prioritized, and assessed for improvement opportunities.	Percent reporting of reportable events and quality of reports as measured by NERC review	95% of reportable events have reports submitted	80% approval according to quality review criteria	5%
15.	Develop and maintain situational awareness capability that meets the needs of FERC, NERC, and applicable registered entities.	Delivery of SAFNR tool	System delivery and testing complete	All U.S. reliability coordinators connected	1%
16.	Deliver reliability assessments of strategic emerging issues that may impact reliability.	Number of special issue reports approved	4 special issue reports approved	6 special issue reports approved	3%

- 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.

	Objective	Measure	Threshold	Target	Weight
17.	Minimize the risk of large scale failures of the bulk power system.	Number of Category 5 events (10,000 MW generation or load loss) not acts of nature		No Category 5 events (excluding acts of nature)	10%
18.	Develop and implement risk management strategies for highest tier reliability risks.	Identify high priority risk management projects and develop plan	2 projects identified and planned	3 projects	1%
		Identify success measures and benchmark	Measures for each project	Benchmarks complete	2%
		Implement plan	Project started	On schedule at yearend	2%
19.	Enhance situational awareness within the electricity sub-sector and with government through ES-ISAC, such as presence at NCCIC and other governmental classified forums.	Establish presence on NCCIC floor	1 ES-ISAC staff have access to NCCIC	2 ES-ISAC staff have access to NCCIC	1%
		Develop and implement initial declassified NCCIC framework in ES-ISAC	Design ES-ISAC wall of knowledge component	Test initial prototype	2%
		Unclassified information products for registered entities based on classified sources	Continually populate ES-ISAC portal with indicator bulletins	Registration on ES-ISAC portal by 50% of registered entities	2%
20.	Develop cyber security risk assessment tools for industry use, including maturity or mode of attack models.	Perform exercises based on attack tree modeling and support DOE maturity model	3 exercises at host entities	6 exercises at host entities, including DOE pilot	2%

- 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.

	Objective	Measure	Threshold	Target	Weight
21.	Assist industry in improving reliability data modeling, including generator and turbine controls and load modeling.	Continue workshops on improved modeling. Engage all three interconnections in model improvement Execute plans to improve models. Prioritize improvements towards specific study	Report on improvement requirements and plan for improvement 2012 models suitable for Frequency Response Studies in the Eastern Interconnection. Document in a report to the PC	Data request to support model improvement Engage EPRI in improve load modeling research	3%
22.	Manage a consistent program for issuing advisories, recommendations and essential actions, and track and report mitigation results. Conduct these activities using tools, processes, and authorities.	Tools for tracking recommendations from alerts, event analysis, and other sources	Specifications for electronic issuance of Alerts and tracking of progress on recommendations	System operational and testing completed	2%
23.	Facilitate the conduct of comprehensive emergency, disaster, and business continuity planning.	Develop and test national security crisis response plan	Develop and review plans; test internally	Test internally and assess during 1 additional exercise, such as Cyber Storm IV	1%

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.

	Objective	Measure	Threshold	Target	Weight
24.	Maintain easy-to-navigate, accessible reliability information through a library of lessons learned from event analyses, best practices, examples of excellence, and other resources for reliability improvement.	Implement NERC public website using SharePoint 2010	Website operational	Implement metadata for rapid search capability	2%
25.	Develop and implement an industry-wide communications plan to build awareness of work by the ERO and industry to improve reliability.	Develop quarterly reporting mechanism to detail ERO activities that addresses BPS risk	Reports for Q2-4 2012	Reports for Q1-4 2012	2%

- b) *Operate as a collaborative enterprise.* The ERO will communicate expectations clearly and foster collaboration to deliver important results in advancing system reliability.

	Objective	Measure	Threshold	Target	Weight
26.	Develop highly qualified and trained staffs at NERC and the regional entities, including enhancement of qualifications in auditing, investigations, enforcement, and other essential staff roles.	Develop certification criteria for critical ERO functions Conduct continuing training on auditing, investigating, root cause, and human factors	Auditor qualifications documented 95% of all auditors and investigators have 2 days of training or more	Investigator qualifications also 100% of auditors and investigators at NERC and regions, programs available to registered entities	2%
27.	Deliver the initial modules of a secure information management system to achieve efficiencies, consistency of outcomes, effective process controls, and more transparent accountability across the statutory functions of ERO enterprise.	Deliver business requirements and functional requirements for one ERO application	Design 2 agreed upon applications	Implement 2 agreed upon applications	3%

- 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.

	Objective	Measure	Threshold	Target	Weight
28.	Develop an ERO-wide risk management program with effective internal controls to ensure the ERO is addressing organizational risks and successfully fulfilling its statutory mission.	Governance established, executive hired and 2012 work plan completed	Governance adopted and executive hired	2012 work plan complete and 2013 activities in business plan filed	1%
29.	Address recommendations and directives from the Three-Year ERO Assessment and previous audits.	Recommendations completed from 3 year assessment	90%	100%	1%
		Recommendations completed from FERC audit and previous audits	90%	100%	1%
30.	Implement additional operating and financial controls to improve resource efficiency and allocation	Budgetary performance	Within operating budget plus carry forward working capital from 2011, plus any approved 2012 working capital expenditures	Within operating budget plus any approved 2012 working capital expenditures	3%



NPCC's Regional Entity Ballot Process on NERC Standards

NPCC, as a cross-border Regional Entity, has the authority under the Regional Delegation Agreement and Provincial MOUs to conduct standards development, reliability assessment and compliance activities. As part of its standards development efforts, NPCC has the responsibility to participate in, comment on, and cast ballots for NERC standards within Sector #10 of the NERC Registered Ballot Body. NPCC also regularly solicits input and coordinates consensus comments, wherever possible, on proposed NERC standards from its Members through the Regional Standards Committee. In determining its vote, NPCC considers both recommendations from Members, representing different and sometimes multiple NERC Sector perspectives, as well as, its independent, unbiased, technical evaluation of potential reliability impacts of a proposed standard from a Regional Entity perspective. In all instances, NPCC's ballot as a Regional Entity in Sector #10 represents the vote of the office of the President and Chief Executive Officer, as informed by the aforementioned input.

In casting its ballot for posted NERC standards, NPCC considers the following in making a determination:

- Does the standard provide an incremental, cost-effective benefit to reliability in Northeastern North America? Although a standard may not be perfect, is there some improvement to the "Status Quo"?
- Were reliability directives received by NERC from Provincial, Governmental and/or Regulatory Authorities addressed?
- Did NPCC or its Member(s) participate in the drafting of the standard and effectively promote critical reliability objectives of Northeastern North America?
- Did NPCC provide comments during the development of the standard, and were NPCC's substantive comments addressed satisfactorily?
- Did NPCC persuade the NERC standard drafting team to address critical reliability related issues (fatal flaws) of importance to its Members and the reliability of the Northeastern North America?
- Did the NPCC Task Forces, Committees and Board of Directors offer any opinions?
- Did NPCC Members offer their proposed voting positions in their respective Sector(s) to NPCC?

March 15, 2012

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Driven Index (SDI)

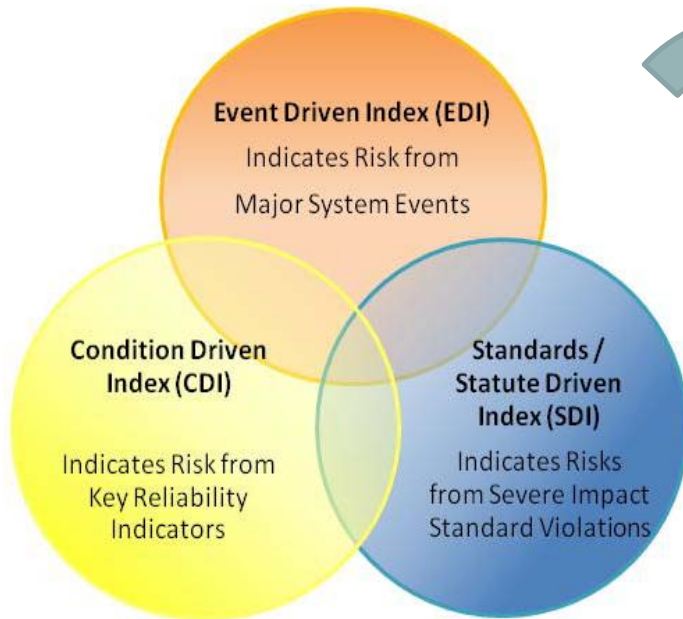
Bill Adams, Chair, OC/PC Performance Analysis Subcommittee
System Operations Manager, Georgia Power Company

CCC Meeting, March 14-15, 2012

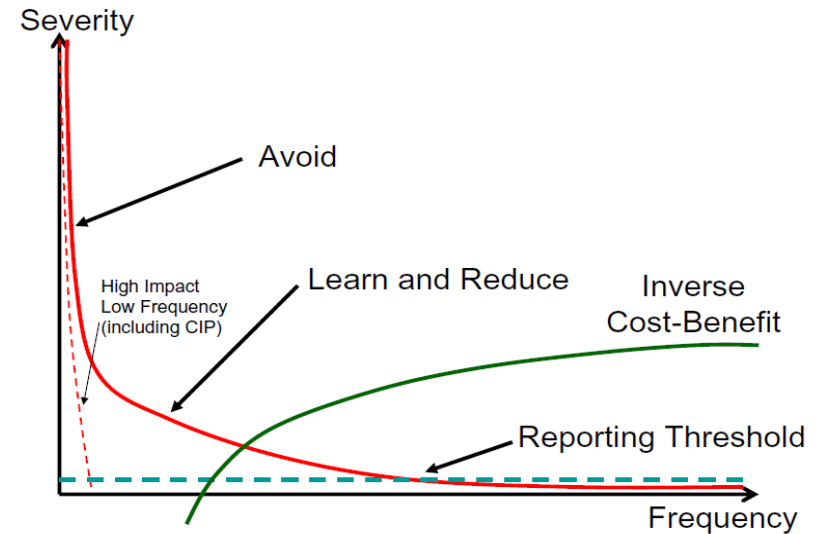
RELIABILITY | ACCOUNTABILITY



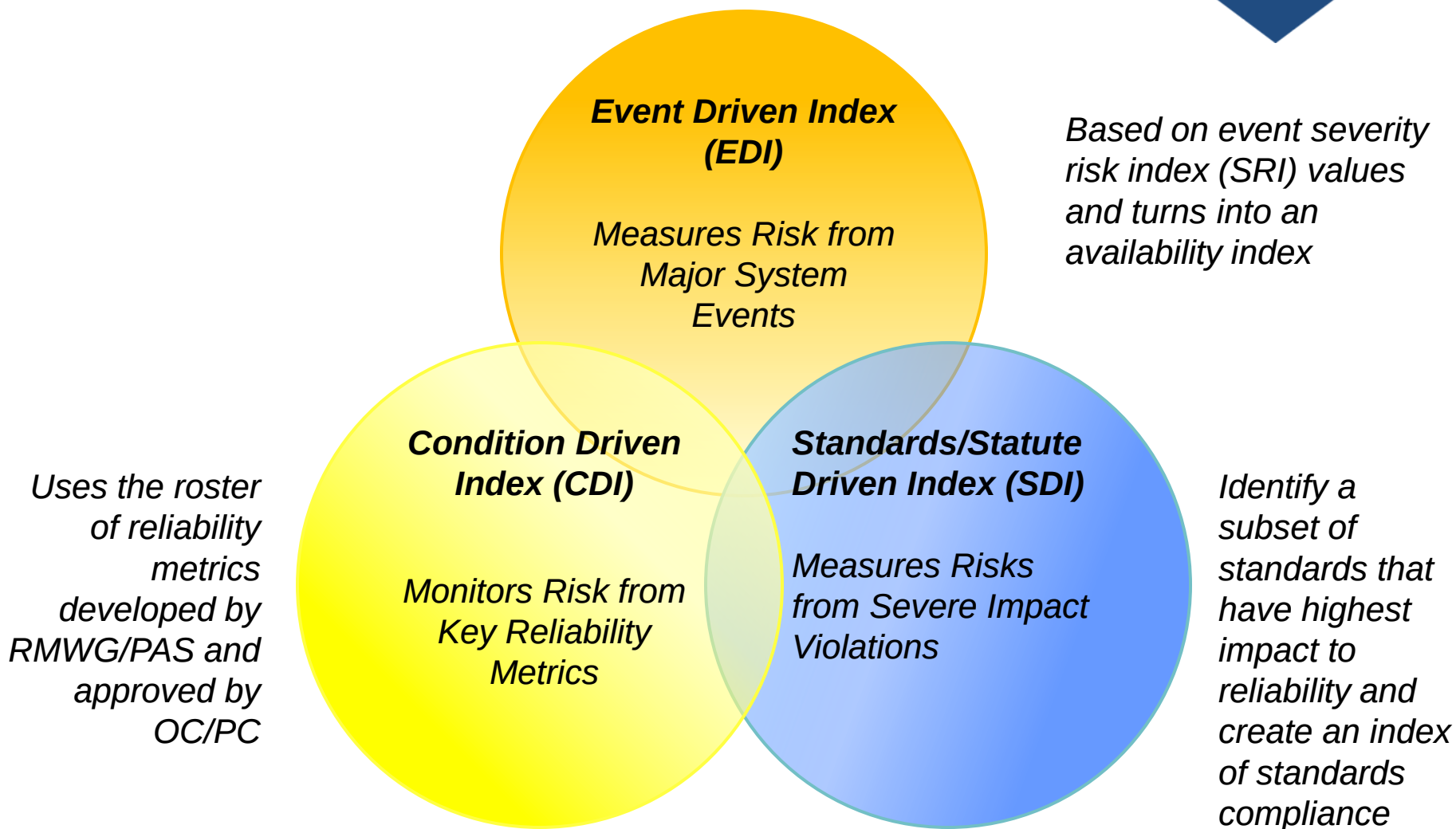
- Status Update
- Standards Driven Index Proposal



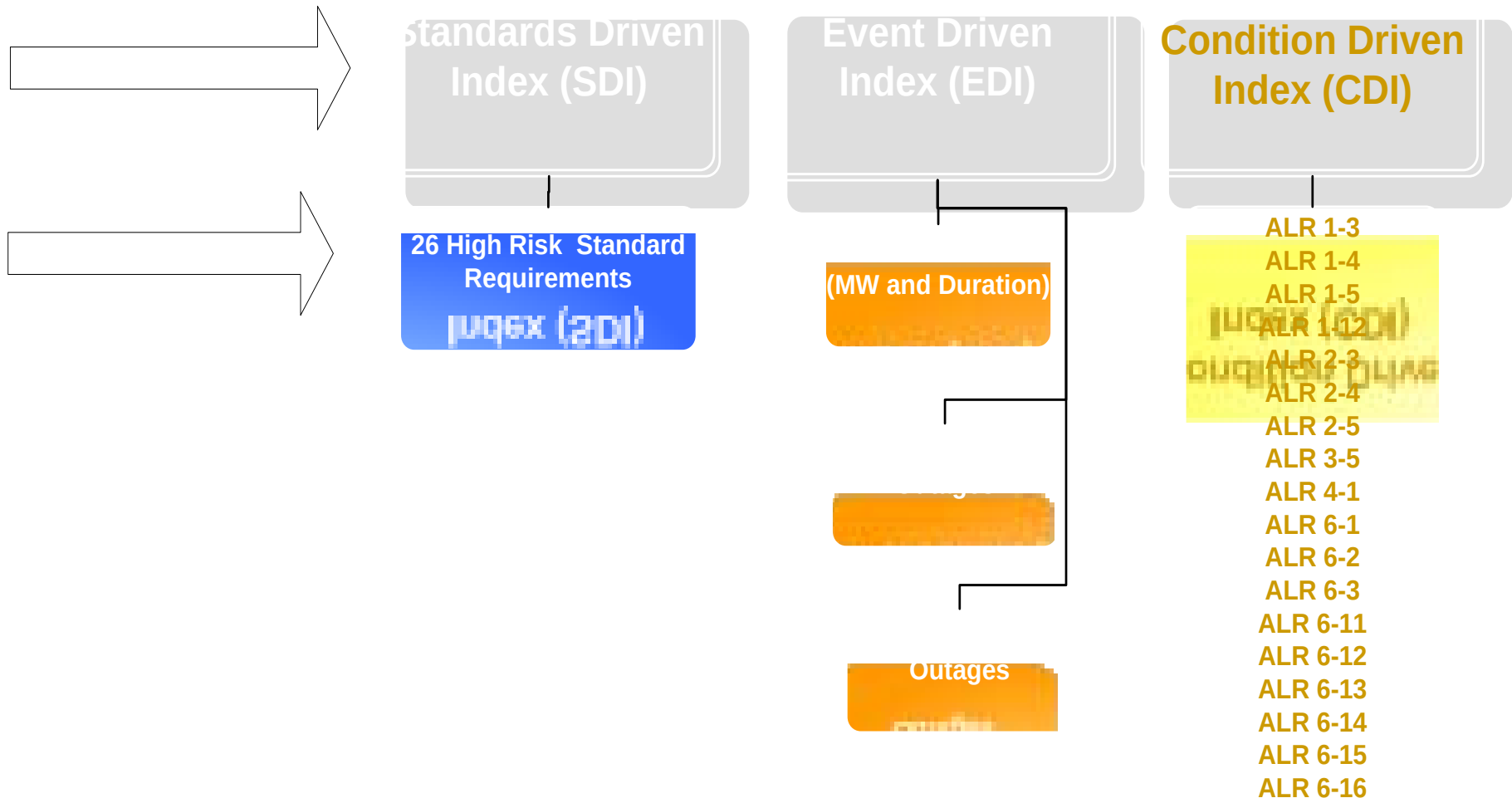
Cornerstone of risk-management concepts



Integrated Risk Indicators



Tiered Risk Measures



- December 2011, the OC/PC approved phased approach to develop 3 integrated indicators
 - Focus on individual reliability performance areas
 - Event Driven Index (EDI) – by March 2012
 - Approved by OC/PC at March 6-7, 2012 Meeting
 - Condition Driven Index (CDI) – by June 2012
 - Standards Driven Index (SDI) – by June 2012
 - Sought input and feedback at September and December CCC meetings

- Average standards compliance rate for 26 high risk requirements
 - Stable indication of daily compliance over a specific time period of interest
- $SDI = (Total\ Compliance - \sum(w_v * NV / NR)) / (Total\ Compliance)$
 - Range from 0 to 100
 - Total Compliance = 1.0* Number of Days in a specific period
 - w_v = weighting of a particular high risk req. violation
 - NV = number of violations for the selected high risk req.
 - NR = number of registered entities required to comply with the req.

Proposed Approach for Standards/Statute Driven Index (SDI)

- Uses High Violation Risk Factor (VRF) (Approved standard requirements only)
- Severe Reliability Impact Statement (RIS)
 - RIS indicates significance of impact on BPS
- Considers Violation Severity Level (VSL)
- Validated against almost 4 year history of violations for most significant standards risks to reliability

	Violation Risk Factor			
Violation Severity Level		High	Medium	Lower
	Severe	198	256	162
	High	96	112	92
	Moderate	77	109	90
	Lower	59	96	80

Proposed Approach for Standards/Statute Driven Index (SDI)

- Severe Reliability Impact Statement (RIS)
 - RIS indicates significance of impact on BPS
- Uses Violation Risk Factor (VRF)
- Demonstrates Violation Severity Level (VSL)
- Similar to daily SRI calculation
- Almost 4 year history violation history of 4,410 confirmed violations

	Violation Severity Level					
Violation Risk Factor		<i>Risk Impact Statement Value?</i>	Severe	High	Moderate	Lower
	High	<i>Severe</i>	25	16	2	6
	High	<i>Non-Severe</i>	312	161	86	384
	Medium	<i>Severe</i>	22	5	2	4
	Medium	<i>Non-Severe</i>	397	106	105	373
	Lower	<i>Severe</i>	11	3	3	2
	Lower	<i>Non-Severe</i>	218	61	67	306

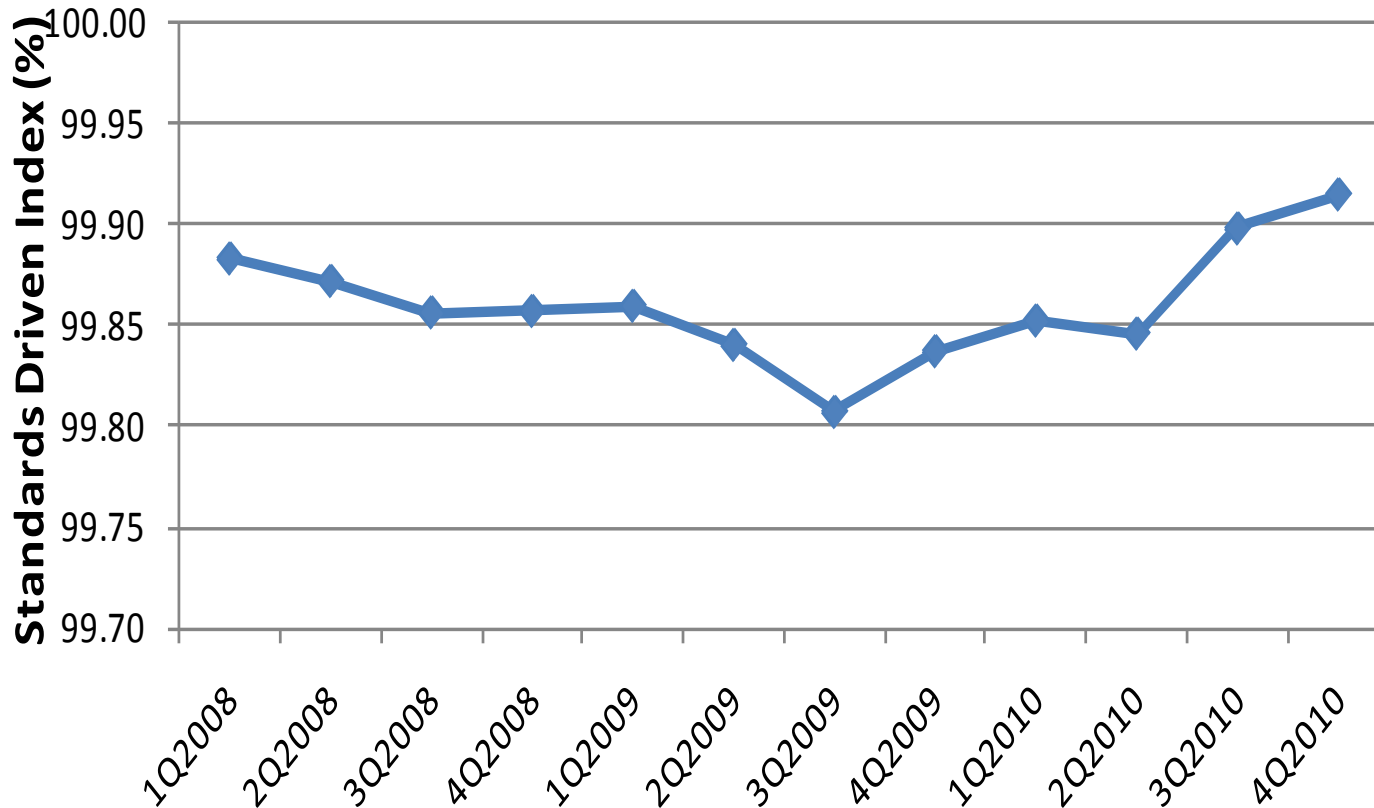
Proposed 26 High Risk Requirements

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.								

** All 26 requirements have high Violation Risk Factor (VRF) and Severe Risk Impact Statements*

- SDI increases if the accumulation of non-compliance is reduced over a trending period
- At a high level, stakeholders can use the tool to measure the compliance and associated reliability risk changes of these days

Preliminary SDI Trend by Quarter

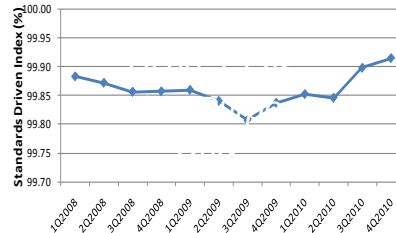
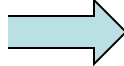


- Historical measure useful for trending and does not address real-time, nor forward-looking compliance performance
- All 26 requirements have same weighting factors
 - As experience with the SDI increases there may be opportunity to transition into a impact-based view
 - Working with CIPC to consider CIP related risk in a separate measure
- As standard requirements change performance and calculation compliance results will need to be vetted and bootstrapped
 - Determination must be made of new requirements versus legacy requirements
 - Performance calculations will have to link old and new performance to create a sustainable long-term view of compliance performance

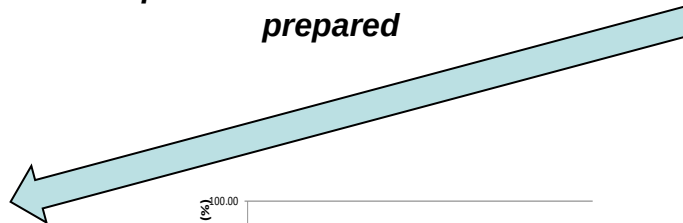
- The PAS recommends that the Compliance and Certification Committee
 - Collaborate with PAS to validate standard requirements which have been designated as bell-weather reliability indicators
 - Collaborate with PAS to validate quarterly/semi-annual performance results
 - Endorse the Standards Driven Index proposal



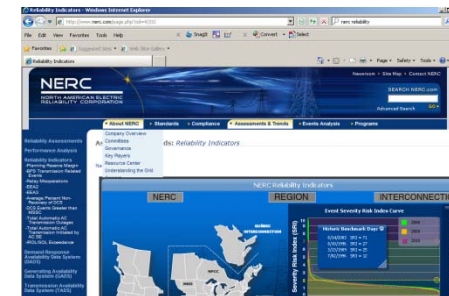
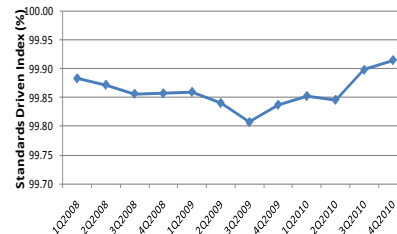
NERC/PAS calculates recent performance



CCC Reviews Performance and identifies issues with trends, calculations, or included standard requirements



NERC/PAS incorporates guidance given by CCC



Final performance is produced

Reliability Indicators Website is Updated with Final Results

Present

- Severity Risk Index
- Adequate Level of Reliability metrics
- TADS
- GADS
- Event Analysis Database
- Event Driven Index (EDI)
- Standards Driven Index (SDI) proposal
- CDI proposal

Work Plan

- Statistically link reliability reduction cause & effect
- Link event, precursor indicators, and outage datasets to explore initiating events
- Find top initiating events
- Develop reliability index framework

Future

- Use the probabilistic cause & effect model to quantitatively measure reliability
- Focus on improving top initiating event performance
- Help focus industry on relevant reliability risks to improve reliability



Questions and Answers

Announcement

NERC Grid Exercise Increases Cybersecurity Readiness; Identifies Enhancements to Improve Security

March 21, 2012

WASHINGTON, DC – The North American Electric Reliability Corporation (NERC) completed its after-action review of the 2011 grid security exercise, GridEx 2011. The review identifies key findings and recommendations for improving the electric industry's cybersecurity programs.

More than 75 organizations, including utilities and U.S. and Canadian governments, participated in the exercise, which was designed to validate the readiness of the industry to respond to a cyber incident, strengthen the crisis response functions of utilities, and provide input for internal security program improvements.

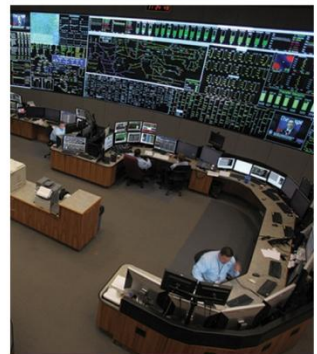
"GridEx provided a realistic environment for organizations to assess their cyber response capabilities," said Brian Harrell, manager of critical infrastructure protection standards, training and awareness at NERC. "Through the exercise interaction, participants forged and strengthened relationships across the cybersecurity community."

Key findings and recommendations in the [2011 NERC Grid Security Exercise After Action Report](#) include:

- Entities possess effective cyber incident response plans, but updates to protocols and guidelines and additional training would enhance preparedness. NERC will develop and raise cybersecurity awareness by conducting focused training opportunities to promote and emphasize incident response and recovery.
- Significant horizontal communication occurs across the industry, but vertical information sharing to NERC and government agencies is limited due to compliance concerns. NERC will coordinate with the Critical Infrastructure Protection Committee Information Sharing Task Force to develop guidance and outreach strategies that create a more secure and trusted environment for information sharing.

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- NERC's Electric Sector-Information Sharing and Analysis Center (ES-ISAC) and Situation Awareness teams effectively coordinated the central communication function, but expediting the FERC review of the NERC alert process, refining call mechanics, and activating the ES-ISAC portal will further enhance the response role.
- Utilities took appropriate steps to secure the grid. NERC will facilitate and support the development of physical security guidance in partnership with the industry and other North American security organizations.
- The NERC emergency standards process should be coordinated to avoid interference with core incident response activities at the entity level. NERC and the industry will review enhancement options to support the overall goal of ensuring bulk power system reliability.

NERC will continue to work with stakeholders and government agencies to further clarify findings from GridEx through root causes analysis, and policy enhancements and improvements. Click [here](#) to download the complete 2011 NERC Grid Security Exercise After Action Report.

###

The North American Electric Reliability Corporation's mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission in the United States to establish and enforce reliability standards for the bulk-power system. NERC has equivalent relationships with provincial and federal authorities in Canada. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel. Learn more at www.nerc.com

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2011 NERC Grid Security Exercise

After Action Report

March 2012

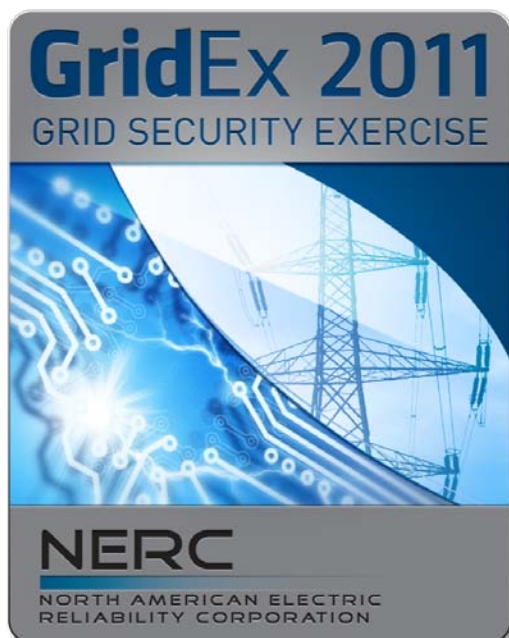
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Executive Summary

The North American Electric Reliability Corporation (NERC) conducted the first sector-wide grid security exercise, GridEx 2011, on November 16-17, 2011. The exercise was designed to validate the readiness of the Electricity Sub-sector to respond to a cyber incident, strengthen utilities' crisis response functions, and provide input for internal security program improvements. In advance of exercise execution, a diverse group of industry stakeholders engaged in an eight month planning process to design the exercise construct, craft a relevant scenario, and recruit a representative player set. GridEx 2011 featured a hybrid discussion and operational-based exercise format that combined a geographically distributed environment for operators and a tabletop exercise for executive leadership. A scenario was crafted to fully engage the diverse stakeholder set, promote coordination during the exercise, and highlight urgent cybersecurity issues facing the sector. The scenario featured advanced persistent threat attributes that propagated across the bulk power system (BPS) and eroded trust in critical grid functions.

Seventy-five industry and government organizations from the U.S. and Canada participated in GridEx 2011. BPS entities included generation and transmission owners, reliability coordinators, independent system operators, and balancing authorities. Key government agencies such as the Department of Homeland Security, Federal Bureau of Investigation, and Department of Energy were also heavily involved. During the one-and-a-half days of live exercise play, participants received sequenced e-mail messages that detailed scenario conditions. Based on this information, players engaged in both internal response measures and external coordination activities across the sector. An Exercise Control cell managed scenario distribution, monitored exercise play, and captured response activities.

Following the exercise, an after action team reviewed player questionnaire submissions, interviews, and exercise communications. The Electricity Sub-sector achieved GridEx objectives and identified key areas for further exploration. NERC and its stakeholders will take steps to address these areas in order to enhance the ability to respond to a coordinated cyber attack on the BPS. Overall, the exercise was widely regarded across industry and government as a critical imperative in preparing the bulk power system (BPS) for a disruptive cyber event.

The GridEx 2011 findings, below, identify key themes and recommendations:

- Entities possess effective cyber incident response plans, but updates to protocols and guidelines and additional training could enhance preparedness. NERC will develop and raise cybersecurity awareness by conducting focused training opportunities for industry and policy makers to promote and emphasize incident response and recovery.
- Significant horizontal communication occurs across industry, but vertical information sharing to NERC and government agencies is limited due to concerns about compliance implications. While entities relied on the ES-IAC as the hub for information sharing and reporting, improved reporting guidance, as it relates to NERC Situation Awareness (SA) and the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), could promote more information sharing. NERC will coordinate with the Critical Infrastructure

Protection Committee (CIPC), Information Sharing Task Force, to develop guidance and outreach strategies that will further enable NERC to create a secure and trusted environment necessary for information sharing.

- NERC's ES-ISAC and SA teams effectively serve a central coordination function, but further expediting the FERC review of the NERC Alert process, refining call mechanics, and activating the ES-ISAC portal could further enhance the organization's response role.
- Utilities took appropriate steps to secure the grid. Because physical intrusions into BPS infrastructure can have grave cyber implications, entities should ensure their response protocols address a coordinated threat. In partnership with industry and North American security organizations, NERC will facilitate and support the development of updated physical security guidance.
- While the NERC Emergency Standards process would expedite urgent standards development, it should be coordinated to avoid interference with core incident response activities at the entity level. NERC and industry will explore enhancements to the Emergency Standards Process that will support the overall goal of ensuring bulk power system reliability.

GridEx provided a realistic environment for organizations to assess their cyber response capabilities. NERC is applying the GridEx recommendations to further strengthen the bulk power systems preparedness and response mechanisms. To capture all relevant information in the final report, NERC is working in close partnership with public sector stakeholders, bulk power system owners and operators, and the NERC CIPC. The observations and recommendations presented in this report will undergo further analysis to help clarify these observations, assess their root causes, and develop policy enhancements and improvements. In addition to the GridEx final report, many participant organizations developed their own internal summary and observation reports.

GridEx offered Electricity Sub-sector organizations a way to test their plans and skills in a real-time, realistic environment and to gain the in-depth knowledge that only experience can provide. Participants exercised response and recovery functions that are critical to responding to a security event. The lessons learned from the exercise will provide valuable insights to guide future planning for cyber emergencies. Through the exercise interaction, participants forged and strengthened relationships across the cybersecurity community. Ultimately, GridEx served as a critical tool that allowed the Electricity Sub-sector to examine closely the growth and evolution of security capabilities.

The Electricity Sub-sector achieved GridEx objectives and identified these key areas for further exploration. NERC and its stakeholders will take steps to address the findings to enhance the ability to respond to a coordinated cyber attack on the BPS.

Introduction

On November 16-17, 2011, NERC conducted the first sector-specific, large-scale grid security exercise, GridEx 2011. The event culminated after eight months of intensive planning and recruiting efforts. The exercise was viewed across industry and government as a training success in preparing the bulk power system (BPS) for a disruptive security event.

This After Action Report provides an overview of GridEx 2011, with a focus on exercise findings and insights. The report also details key aspects of planning, execution, and the after action process. NERC will leverage lessons learned from the exercise to enhance its own response capabilities and promote cybersecurity preparedness across the BPS.

NERC initiated GridEx 2011 to validate the electricity industry's current readiness to respond to a cyber incident. The event assessed NERC's and industry's crisis response plans in an effort to strengthen security processes and capabilities. The engagement also identified areas for improvement in cybersecurity programs and incident handling capabilities for NERC and its member entities.

Modeled after the Department of Homeland Security's (DHS) Cyber Storm series, the exercise featured a distributed exercise design that enabled participants to respond to scenario events from their normal work stations. Participants consisted of representatives from NERC, Regional Entities, registered entities, and select industry and government bodies. In parallel, GridEx engaged NERC's executive decision makers, as well as senior-level government and industry stakeholders through a discussion based tabletop exercise (TTX) format. This engagement enabled leadership to assess, test, and validate existing command, control, and communication plans.

Participation

The GridEx planning team recruited player organizations through a variety of means, including a sector-wide outreach program, leveraging previous exercise relationships, and interacting with government and sector coordinating bodies. The planning team identified a core group of exercise planners to attend planning conferences, shape the objectives, support scenario design, and contribute to the after action process. In addition, from this core group of exercise planners, the planning team established two levels of organizational commitment: Full Player and Monitor/Respond (M/R). Full Player organizations fully engaged in exercise play and external coordination, while M/R entities followed the scenario progression and considered scenario implications internally. These two forms of exercise play enabled organizations to determine their level of involvement based on resources, timing, and other factors. Seventy-five organizations from the U.S. and Canada participated in GridEx 2011, including 48 utilities, 21 government and academic organizations, and six Regional Entities. Figure 1 reflects the broad representation of GridEx participants.

Figure 1: GridEx Participant List

GridEx Participants		
Utilities - Alliant Energy - Ameren Corporation - Arkansas Electric Cooperative - Bonneville Power Administration - Brookfield Renewable Power - Burlington Electric Department - Cal ISO - Dayton Power and Light Company - Duke Energy - Duquesne Light Co. - EDP Renewables North America, LLC - Entergy - ERCOT - Georgia Transmission Corporation - Great Lakes Power Transmission - Hydro One - Iberdrola Renewables - Independent Electricity System Operator - ITC Holdings - Lakeland Electric - Long Island Power Authority - Massachusetts Municipal Wholesale Electric Company - Midwest ISO - National Grid - Nebraska Public Power District - New York Power Authority - Northeast Utilities - Northern Indiana Public Service Corporation - NY ISO - Oklahoma Gas & Electric - Ontario Power Generation - Orlando Utilities Commission - Pacific Gas & Electric - PEPCO Holdings, Inc. - PJM - Progress Energy - Public Service Electric & Gas Company - Sempra Energy Utilities - Southern Company - Southern California Edison - South Mississippi Electric - SPP - RTO - TECO Energy - Tennessee Valley Authority - Western Area Power Administration - Wisconsin Public Service - Xcel Energy		Regional Entities - MRO - NPCC - RFC - SERC - TRE - WECC
		Government/Academia/Other - ABB - Canadian Electricity Association - Canadian Incident Response Centre - Critical Infrastructure Criminal Intelligence/Royal Canadian Mounted Police - DHS/National Cyber and Communications Integration Center - DoD/Cyber Crime Center DCISE/DIB-CERT - DOE - Edison Electric Institute - EnergySec - EnerNex - FBI - FERC - ICS-CERT - Lofty Perch - National Guard, Critical Infrastructure Protection Program - Natural Resources Canada - North American Transmission Forum - Pacific Northwest National Lab - Public Safety Canada - University of Illinois - Utility Services

Exercise Objectives

The planning team developed the GridEx objectives to guide recruiting, scenario development, and after action activities. The GridEx objectives included community concerns and current initiatives; however, each organization had the opportunity to create its own objectives to focus internal efforts. Through the one-and-a-half day exercise, players successfully achieved the three pre-established objectives, outlined below.

Objective 1: Validate the current readiness of the electricity industry to respond to a cyber incident and provide input for security program improvements

Players achieved this objective during the execution of GridEx as entities engaged in realistic internal evaluation and incident response activities that supported grid reliability. Organizations were able to assess a number of departments including Operations, Information Technology (IT), Communications, Physical, and Cybersecurity functions. During exercise play, participants successfully engaged their protocols to guide their actions. Participating organizations identified strengths, gaps, and areas for improvement in their incident response plans and procedures. While enhancements were identified to be instituted, the industry validated its preparedness for a disruptive cybersecurity event.

Objective 2: Exercise NERC and industry crisis response plans and identify gaps in plans, security programs, and skills

GridEx 2011 enabled NERC to fully exercise its crisis response plan and assess strengths and gaps within its protocols. During the exercise, NERC distributed a series of alerts that aided in informing the electricity community on the escalating cyber incident. Entities relied on the ES-ISAC as the hub for information sharing and reporting. Player feedback and communication with NERC during the exercise enabled successful testing of their procedures and crisis response plans. In addition, participating organizations and NERC were able to assess and evaluate their incident response programming during the planning phases of the GridEx engagement.

Objective 3: Assess, test, validate existing command, control, and communication plans for key NERC stakeholders

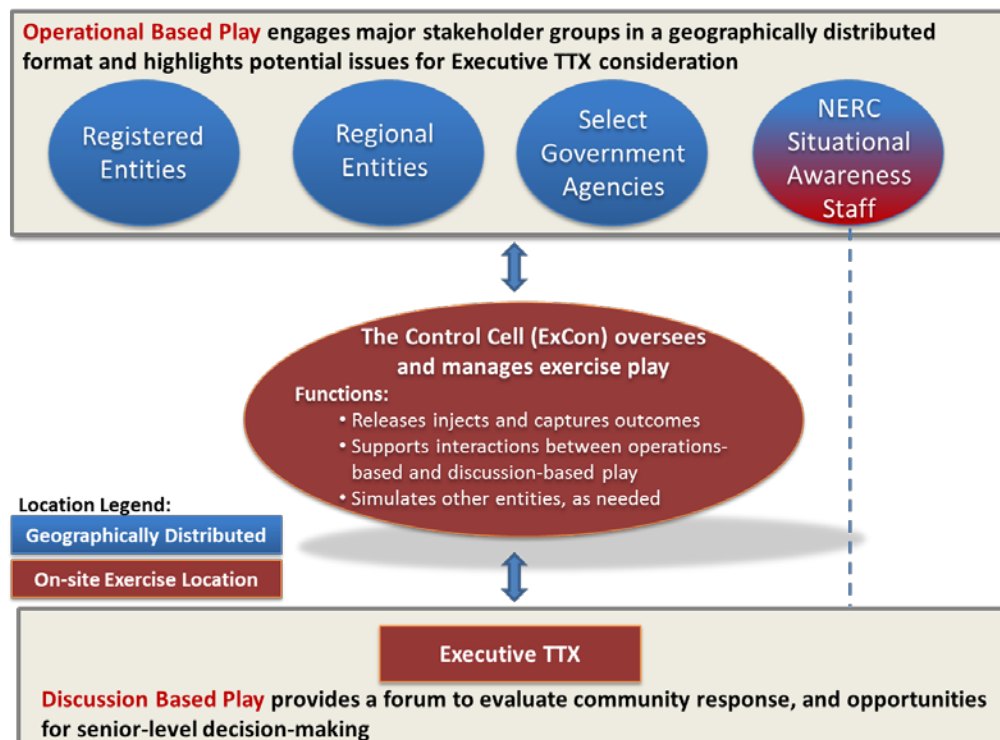
Prior to exercise execution, planners recognized the broad set of actors involved in responding to a cyber incident and the importance of proper stress testing of communications plans. The player set represented the electricity community as a whole, and enabled both internal and external communication to function successfully. Players used the player directory to identify key resources to contact. Scenario events allowed organizations to successfully test their command, control, and communications plans internally across functions and externally across the BPS. The exercise enabled players to consider alternative communications and operations approaches in a compromised environment. The planning process also promoted communication and relationship-building across the sector and across geographic borders.

Exercise Design and Scenario Construct

GridEx design embraced a combined approach with operational and discussion-based exercise tracks (see Figure 2). The operational construct featured a geographically distributed player set. The players received sequenced messages via e-mail that chronologically detailed scenario conditions. Based on this information, players engaged in both internal response protocols and coordination activities across the sub-sector, and to relevant industry and government bodies. The discussion-based Executive TTX, conducted concurrently with distributed play, focused on executive decision-making. Senior-level officials from the NERC Board of Trustees, electricity industry, and relevant government agencies participated in the Executive TTX to discuss urgent policy issues that could be escalated to an executive level. These issues included compliance concerns, widespread reliability issues, and external affairs.

During the planning phase, organizations were asked to commit to either Full Player or M/R status. Full players were expected to fully engage in exercise play. They also had the ability to tailor and adapt injects to suit their organizations' objectives and contribute to the after action process. M/R organizations received all injects, but were not required to fully engage in the exercise or report findings. M/R organizations were permitted to participate in all coordination calls, and provide limited after action feedback. An advantage for M/R organizations was participation in a sector-wide exercise without substantial resource requirements. Most players participated in GridEx from their work locations and engaged in exercise play via e-mail and other standard communications channels.

Figure 2: GridEx Construct



For each entity within the distributed player set, Controller/Evaluators (C/E) were designated to facilitate and record exercise play at the local or organizational level. C/Es ensured players were well-equipped to engage in the exercise, and liaised with Exercise Control (ExCon) throughout the event. In the distributed exercise construct, C/Es were asked to oversee interactions within their organizations and capture key observations that were not visible to the planning team within ExCon.

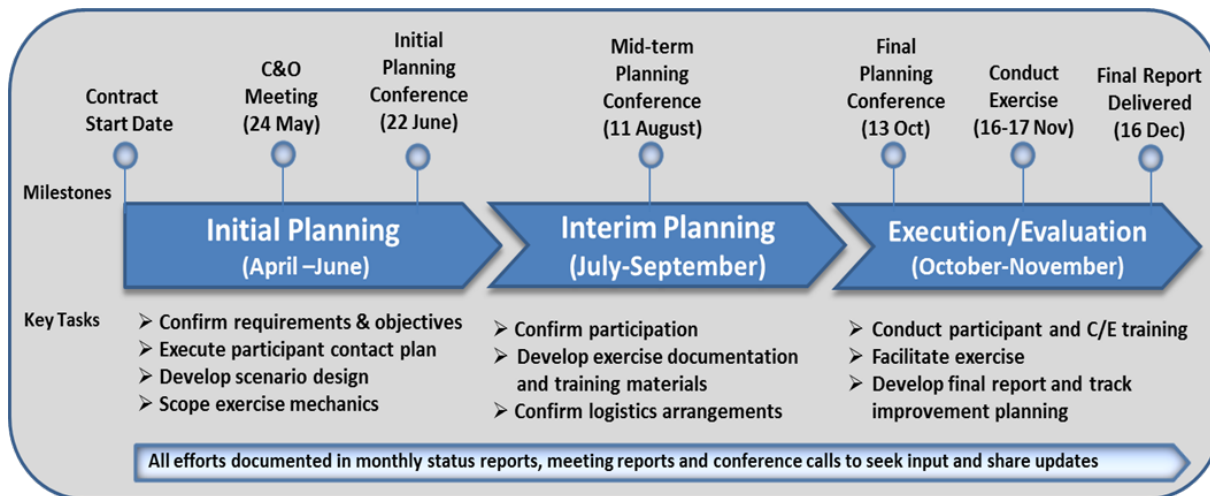
The GridEx scenario was crafted to achieve exercise objectives and fully engage the diverse GridEx stakeholder set. The scenario had broad relevance among players, promoted coordination during the exercise, and highlighted urgent issues facing the sector. While the technical feasibility of the scenario was vetted by experts across the industry, the planning team adjusted aspects of the exercise to ensure wide applicability and that players achieved exercise objectives. The scenario began notionally with physical intrusions into substations and back-up control center infrastructures. Initially believed to be copper theft, entities soon learned the intruder also committed cyber tampering. The bad actor introduced sophisticated malicious code (malware) capable of corrupting Supervisory Control and Data Acquisition (SCADA) system calculations and eroding inter-party trust relationships. The malware also tunneled to corporate networks, disrupting key business processes. The code leveraged communications Protocols as an intermediate attack vector to deliver malicious code across the North American BPS.

Within the first two days of exercise play, operators and IT professionals engaged in incident response protocols, while working to maintain system reliability and identify the root cause. As entities observed a common pattern of suspicious behavior across the BPS, they leveraged both formal and informal communications mechanisms to share information. The simulated Reliability Coordinator Information System (RCIS) and Electric Emergency Incident and Disturbance Reports (OE-417) widely communicated observed impacts and notified relevant government agencies. NERC and the ES-ISAC served a central coordinating function by establishing a common operating picture and providing practical guidance to industry. The U.S. Federal Bureau of Investigation (FBI) worked closely with impacted entities to investigate the reported break-ins and understand the full scope of illegal activity. The Industrial Control Systems Cyber Emergency Response Team (ICS-CERT), in coordination with the ES-ISAC, distributed bulletins with malware indicators and initial defense measures for entities. For a more detailed explanation of the scenario, see Appendix A.

Exercise Planning and Execution

The GridEx planning process consisted of four planning meetings that aided in the development of the scenario, exercise design, and outreach for the exercise. In addition, the planning team participated in several interim conference calls and informal discussions to expand recruitment and refine scenario elements.

Figure 3: GridEx Planning Timeline



Concept Development Phase

NERC held the Concept and Objectives (C&O) Meeting on May 24, 2011. During the C&O Meeting, the planning team discussed and reviewed the GridEx objectives, and reviewed the project timeline and key events. The group also identified exercise roles and recruitment strategies. NERC created a Steering Committee to attend all meetings and planning conferences. The Steering Committee was influential in shaping the objectives and exercise scenario and assumed an expanded role in the after action input and review process. The planning team then confirmed two levels of player participation for GridEx: Full Player and M/R. These levels enabled varying resource commitments and levels of influence during planning. During the C&O Meeting, participants took preliminary actions to develop the GridEx scenario. The scenario would focus on a cyber attack on the Electricity Sub-sector, posing reliability concerns that would trigger crisis response planning and coordination. NERC strongly encouraged the group that the scenario should be credible and realistic and reflect the current response capabilities of the sub-sector. An advanced persistent threat attack was identified to properly achieve exercise objectives. Finally, the planning team agreed the scenario should incorporate both cyber and physical elements, to the greatest extent possible.

Initial Planning Phase

During the Initial Planning Conference (IPC) on June 22, 2011, the planning team developed key themes for the scenario, reviewed DHS' cyber programs, and identified stakeholder coordination and information sharing procedures.

Given the diverse player set, planners agreed that the scenario should have far-reaching impacts to exercise the plans and processes of all players. In addition, planners determined that the scenario should escalate quickly during exercise play to fully engage incident response plans and promote coordination across the sector. After planners confirmed the scenario themes, they developed a written narrative. The narrative featured key events, timing, and expected player actions. The narrative would ultimately be leveraged to create individual injects for exercise play. The IPC also featured a discussion on the National Cybersecurity and Communications Integration Center (NCCIC) and the National Cyber Incident Response Plan. During the discussion, representatives from DHS' National Cyber Security Division (NCSD) assisted in defining parallel government activities, and sensitized the group to potential federal cyber response activities.

Another key step in the planning process was shaping stakeholder outreach activities. As planning efforts accelerated, the Steering Committee advanced scenario development and outreach efforts. To aid in the planning process, planners activated a SharePoint site as a central repository for document sharing and editing within the trusted community. Contributors could read, upload, download, and edit documents based on assigned user privileges.

Mid-term Planning Phase

The Mid-term Planning Conference (MPC) was conducted on August 11, 2011. Outreach and recruitment activities generated sector-wide interest in GridEx. DHS representatives were invited to brief the group on NCSD and NCCIC policies and procedures in place for a potential cyber incident. In addition, an ES-ISAC representative briefed the group on the organization's role in responding to a cyber incident. The group focused on maturing the scenario narrative by discussing scenario timing, attack attributes, and operational impacts.

As the scenario grew more sophisticated and nuanced, planners were reminded to maintain operational security and to keep details within a trusted circle. Throughout the mid-term planning phase, organizations continued to establish their level of participation, along with designating Lead Planners and C/Es. The distinction between Full Player and M/R organizational roles was further clarified to ensure that entities of varying resources and availability could engage at some level. By the mid-term planning phase, both the GridEx objectives and overall execution construct were confirmed.

Final Planning Phase

The Final Planning Conference (FPC) was held on October 13, 2011. During the FPC, planners added granular detail to the scenario and initiated the Master Scenario Events List (MSEL).

Facilitators also provided a final recap on the GridEx exercise construct. In addition, planners further defined the role of C/Es. For Full Player organizations, C/Es were instructed to conduct internal orientation sessions to ensure player preparation for exercise play. C/Es identified internal players that represented the broad response roles that would be engaged during conditions portrayed in the GridEx scenario. For all GridEx participants, information sharing was considered a core exercise activity. To facilitate proper information sharing, the GridEx support staff created a player directory featuring every player and C/E participating in the exercise.

In the final weeks before the exercise, planners finalized logistical and technical scenario details. The planning team communicated the after action process and requirements for both C/Es and players. The planning team created and distributed a C/E Handbook to all C/Es and M/R players. The C/E Handbook was a central reference document containing GridEx background, objectives, schedules, exercise design, and communication protocols. The planning team hosted a C/E Orientation Call to walk through the handbook and answer any final questions regarding GridEx conduct.

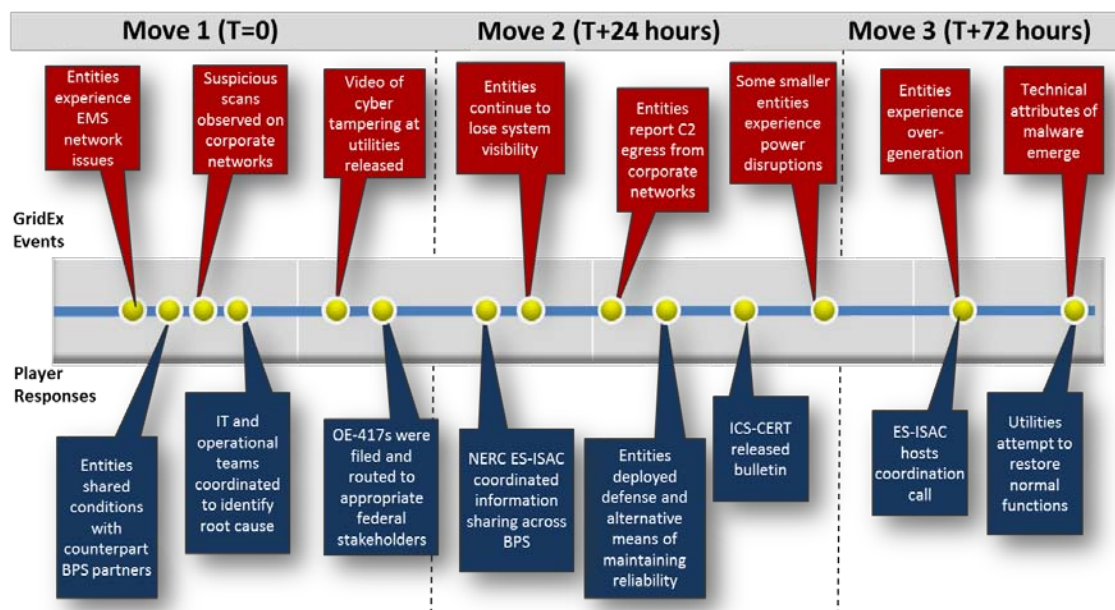
Exercise Execution Phase

GridEx was conducted over a day-and-a-half, on November 16-17, 2011. ExCon consisted of a broad representation of the Electricity Sub-sector, including NERC staff, industry professionals, control system experts, and regional representatives. They managed and transmitted injects from a dedicated email account, monitored exercise play, liaised with C/Es, and tailored injects dynamically based on exercise outcomes. ExCon also simulated non-represented entities when needed, serving as telecom operators, control system vendors, and independent system operators. ExCon supported a help desk phone line and email account, responding immediately to player and C/E questions or concerns. The ExCon also hosted three C/E calls that gave planners more visibility into distributed interactions and clarified any outstanding issues.

The GridEx scenario was divided into three moves. Moves One and Two occurred on November 16, 2011 and with Move Three occurring on November 17, 2011. Planners initiated both exercise days with mock news videos that established a context for exercise play and generated enthusiasm for the GridEx activity among players. As detailed in the Scenario Narrative (see Appendix A), each exercise move presented a series of scenario events to which players responded. During exercise play, ExCon monitored interactions and ensured players were fully engaged in the activity.

Figure 4 below illustrates GridEx scenario events and corresponding player actions as observed by ExCon. Following the conclusion of live exercise play, ExCon hosted a hotwash teleconference for the C/Es and M/R players. This hotwash provided an opportunity for participants to report initial insights and give feedback on the exercise and officially concluded the GridEx engagement. NERC's contractor, Booz Allen Hamilton, delivered the After Action Report to NERC on December 16, 2011.

Figure 4: Scenario Activities by Move



GridEx Findings

The GridEx 2011 findings were developed through the review and analysis of exercise data, stakeholder interviews, and hotwash feedback. C/E calls and the final exercise hotwash provided initial field observations for organizing after action findings. The GridEx planning team reviewed After Action Questionnaires from each of the participating organizations to identify common themes and insights. The planning team also conducted individualized interviews with key stakeholders in ExCon to gain real-time assessments of exercise interactions. Finally, the team merged insights from the Executive TTX with distributed outcomes to ensure the findings reflected an integrated perspective.

Finding #1: Entities effectively applied internal security protocols and cyber incident response measures in an effort to maintain grid reliability and mitigate the impacts of a sophisticated cyber attack. Information sharing across business units and departments occurred frequently, but areas for improvement emerged.

Supporting Observations and Recommendations

- Participating entities successfully activated internal cyber incident response command structures and external crisis management teams to address both technical impacts and broader public-facing implications. Internal policies and procedures promoted order in an unpredictable situation, but the need to update and refresh guidelines was widely acknowledged. The exercise reinforced the importance of maintaining a Cyber Security Incident Response Plan in advance of an actual incident. Several entities learned that some internal policies were outdated due to infrastructure upgrades, staff turnover or new Critical Infrastructure Protection (CIP) requirements. In addition, some entities noted the importance of updated and current intercommunications plans between operational-level staff and senior management in a rapidly evolving crisis environment.
- Operational and IT staff shared impact assessments and attack implications as the scenario escalated. Several entities noted that this interaction represented the first time these functional groups had successfully coordinated efforts during a security incident or drill. While some organizations readily shared information across functions, others worked in isolation and struggled to recognize implications for both operational and IT assets. In the early phases of the scenario, some business units such as generation and transmission operators also noted that cross-department information sharing could have occurred in a more proactive manner. Entities can develop training scenarios that would promote more understanding of operations/IT interdependencies and reinforce cross-functional coordination.
- Entities reported the need to establish clearer thresholds that can rapidly distinguish a common operational issue from a major cybersecurity incident. While scenario escalation ultimately led players to activate their cyber incident protocols, some entities

were delayed in acknowledging the full scope of the event. Complicated protocols and diverse infrastructure can lead to tentative responses to infrequent events. Incident response plans should establish clearly defined thresholds that clarify expectations and the level of urgency based on a specific set of operational metrics. Some entities also applied weather event response protocols to the cyber sabotage scenario. While some operational parallels exist, organizations should distinguish cyber response doctrine from those employed during a weather emergency.

- Based on scenario conditions, utilities undertook the appropriate measures to protect assets, mitigate impacts, and maintain grid reliability. These steps included disconnecting the communication protocol networks, relying on manual operations, performing forensics to identify root cause, and isolating corporate networks to contain propagation. While these steps were consistently taken in a coordinated fashion, entities must continue to evaluate the resource requirements and operational implications of such measures. For example, several utilities did not fully recognize the staffing requirements of extended manual operations. Cross-training personnel to perform multiple functions in a crisis situation could alleviate some staffing constraints.
- The exercise highlighted a heavy reliance on e-mail, teleconferencing, and other technology that enables coordination in crisis conditions. In a potentially compromised environment, where communications mechanisms could be untrustworthy, alternate information sharing mechanisms and protocols should be developed.

Recommendations Summary

- Review and refine incident response plans and protocols to ensure applicability and relevance to operational environment
- Establish clearer thresholds to distinguish common issues from major cyber incidents
- Strengthen communications channels between IT and operational personnel
- Identify alternative communications means in crisis situations

Finding #2: Horizontal communication that occurred among utilities was extremely robust but vertical information sharing can be improved. While BPS entities shared information readily, communication with NERC and government agencies, were often not as frequent or comprehensive.

Supporting Observations and Recommendations

- A broad representation of the BPS, including generation and transmission operators, reliability coordinators, balancing authorities, and independent system operators exchanged information as scenario impacts escalated. This information exchange

enabled players to validate conditions and acknowledge the coordinated nature of the sabotage. Entities relied heavily on RCIS posts to gain better situational awareness of conditions across the BPS. For example, RCIS was the first mechanism to broadly disseminate the possibility of cyber tampering originally considered to be copper theft.

- The quality of information sharing and reporting to NERC’s ES-ISAC and relevant government agencies was not as frequent or comprehensive as the communication occurring across the BPS. Several entities did report break-ins and potential cyber sabotage to the FBI, but not to other relevant bodies. Despite the assurance that NERC reporting would not be used for compliance purposes, several entities expressed hesitation in sharing sensitive information regarding compromised critical cyber infrastructure. One entity indicated that it was contacting corporate legal for “permission” to report to the ES-ISAC. This trust deficit significantly impeded entities’ willingness to share information that could have supported the ES-ISAC’s role in ensuring grid reliability. As a result, ES-ISAC’s information gathering content was often limited to OE-417 filings and hampered by the NERC Standard EOP-004 time requirements. NERC has recently taken additional steps to clarify this separation between compliance and the ES-ISAC. Further publicizing and communicating ES-ISAC responsibilities will address concerns about compliance repercussions stemming from entity reporting, and will likely enhance vertical information sharing. NERC can also better reinforce the benefits and incentives for reporting upwards.
- Some entities reported that a lack of clear and consistent reporting protocols inhibited their ability to share information vertically. Utilities cited the overlapping nature of certain compliance procedures found in NERC Standards CIP-001, CIP-008, EOP-004, and the OE-417, which created redundancies in a period of severe resource constraints. Reporting to NERC can be streamlined to reduce duplication and clarify information sharing channels. An updated Incident Reporting Guidelines document with improved guidance on non-regulatory information sharing and a reporting flow chart can help to illuminate the vertical communication protocols that NERC relies on during a major cyber event. Entities also acknowledged the need to review their own protocols for sharing information vertically and clarify what constitutes a reportable event.
- While regional entities supported coordination in their respective areas, information sharing between registered entities, regional entities and NERC can be improved. Regions hosted calls with their impacted entities, but NERC was not consistently invited to these interactions. Some utilities also reported that they were not included in region-specific update calls. In an unfolding emergency, utilities should ensure that both their regional entities and NERC are included in status updates. Conversely, NERC should include the appropriate regional entities on communications to utilities.

Recommendations Summary

- Establish a process or mechanism that enables NERC to capture relevant and/or urgent RCIS post content to strengthen incident response
- Conduct ES-ISAC outreach and communicate incentives to improve vertical information sharing
- Update and disseminate NERC incident reporting guidelines that reduce redundancies and clarify reporting channels with a vertical communications flow chart

Finding #3: NERC fulfilled its role as the central coordinating body for maintaining reliability across the BPS. By developing alerts and hosting industry coordination calls, NERC promoted information sharing and coordinated mitigation efforts to counter the scenario impacts. Although information sharing mechanisms did promote broader awareness, the exercise identified several areas for refinement and clarification.

Supporting Observations and Recommendations

- The ES-ISAC and NERC SA coordinated with ICS-CERT to craft and transmit two ICS-CERT alerts during the exercise. The ICS-CERT team developed timely and actionable guidance on the notional GridEx malware. The ES-ISAC reviewed this content and incorporated it into NERC Alerts for impacted entities. Although the sequence of events did include some exercise artificialities, NERC was able to reinforce its relationship with ICS-CERT and strengthen its NERC Alert process. The alerts promoted awareness of the situation quickly, giving impacted entities mitigation solutions to maintain reliability. NERC should continue to refine its communications channels to ensure that it can disseminate critical information to its stakeholders before they learn of it through media or other sources. A joint information center that can coordinate NERC/DOE/Federal Energy Regulatory Commission (FERC) messaging could support the rapid release of consistent information and avoid a surprise where entities first learn of unfolding events from the media.
- While the ES-ISAC and NERC SA developed and transmitted NERC Alerts rapidly during exercise play, real-world constraints could hamper the expeditious release of urgent updates. The ES-ISAC is bound by requirements stemming from Section 810 of its Rules of Procedures that require up to a possible five day review time by FERC for approvals prior to release. This requirement could adversely affect NERC's ability to share real-time information and guidance to registered entities during disruptive events.
- NERC Hydra exchanges and larger coordination calls were effective in fostering a common operating picture among entities. Although NERC can further clarify call mechanics, most entities found them helpful and informative. Several utilities expressed concern about the security of the conference bridge, particularly unauthorized participation from media. NERC frequently refreshes bridge security access codes to prevent non-essential organizations from participating. NERC conducts separate calls for media and other non-BPS stakeholders. Existing security measures

should be widely publicized to registered entities to promote confidence and broader participation in calls.

- As scenario impacts eroded confidence in conventional communication means, entities considered more trusted mechanisms for sharing information. Since information sharing via standard email or teleconference could be rendered untrustworthy, entities noted that the ES-ISAC portal would address the trust gap by providing a reliable and secure mechanism for sharing information. Entities encouraged the accelerated activation of portal functionality. The ES-ISAC can better educate industry on such services through presentations and awareness activities.

Recommendations Summary

- Support the revision of FERC review and pre-approval requirement of NERC Alerts to ensure timely release of information and guidance to registered entities
- Clarify and disseminate information regarding NERC conference bridges to promote confidence in the security and confidentiality of coordination calls
- Expedite the activation and availability of ES-ISAC portal to enhance trusted information sharing channels and increase awareness of existing ES-ISAC tools to industry

Finding #4: NERC's ES-ISAC and Situational Awareness (SA) teams collaborated closely to support a coordinated BPS response to the GridEx scenario. Despite generally effective coordination, improvements can be made in defining individual roles and responsibilities during a High Impact, Low Frequency events.

Supporting Observations and Recommendations

- NERC's SA staff and the ES-ISAC coordinated closely in developing an attack sequence and hosting industry conference calls to promote situational awareness. The ES-ISAC successfully tested its Cyber Events and Analysis workflow to obtain a strong understanding of unfolding events. While conference calls were well-run and informative, roles and expectations require further definition. Players noted some overlap in reporting content and felt agenda items could be better streamlined. Developing call scripts to communicate standard messages could help address this issue.
- During the rapidly evolving scenario events, NERC SA and the ES-ISAC uncovered some redundancy and parallel responsibilities. While the two groups are heavily reliant on one another to coordinate with regions, gather information from BPS entities, develop guidance and host information sharing forums, some confusion around their respective duties could inhibit responsiveness in a cyber event. The development of formal roles and responsibilities between NERC ES-ISAC and the SA team, agreed upon by teams and senior leadership, would address overlapping functions. These decisions should be communicated to stakeholders, as some entities expressed confusion regarding their individual purviews. The ES-ISAC, in coordination with NERC SA, should consider developing outreach presentations to registered entities to highlight and reinforce its incident response role.

Recommendations Summary

- Streamline coordination call facilitation by developing standardized call scripts
- Clarify incident response roles and responsibilities between NERC ES-ISAC and SA teams to reduce overlap and enhance responsiveness

Finding #5: Entities responded to initial physical intrusion information with conventional measures but cyber threats should be considered when addressing BPS break-ins.

Supporting Observations and Recommendations

- Upon learning of a physical break-in at substations or back-up control centers, several entities engaged their physical security procedures and reported the apparent copper theft. The scenario highlighted the need to proactively evaluate physical intrusions as an avenue for more disruptive cyber tampering. While conventional copper theft is commonplace across the BPS, security personnel should be sensitized to the cybersecurity implications of a seemingly innocuous event.
- Once cyber tampering was confirmed at facilities across the U.S. BPS, entities consistently reported the situation to appropriate law enforcement authorities. This information was successfully routed vertically through RCIS and, ultimately, in OE-417 reports.

Recommendations Summary

- Sensitize staff to cybersecurity threats stemming from physical intrusions
- Ensure incident response protocols address combined physical/cybersecurity considerations

Finding #6: While the NERC Emergency Standards process could effectively develop binding standards in response to an imminent issue regarding the bulk power system, the process could interfere with core incident response activities at the entity level.

Supporting Observations and Recommendations

- Entities' primary focus during GridEx was mitigating malware impacts and maintaining grid reliability. Players expressed concern that the Emergency Standards directive could divert scarce resources from ongoing recovery efforts to a less mission-critical activity.
- Utilities had little awareness or visibility into the Emergency Standards program. Players expressed concern that the Emergency Standards provision could divert scarce resources from ongoing recovery efforts to a less mission-critical activity. To ensure efficacy and support for the process, NERC should more broadly communicate its function and requirements. NERC can also clarify if the standards are permanent or

have some form of “sunset” provision. Conversely, entities must designate the appropriate personnel to address Emergency Standards directives, should they occur. Utilities reported issues with executing the confidentiality agreements sent as part of the Emergency Standards activation. Several participants noted that the requested turn-around timeframe for the agreement was impractical, while others did not understand the context in which the confidentiality was being assigned.

Recommendations Summary

- Consider resource requirements and improved process for entities to address NERC Emergency Standards in the midst of a security event
- Use the Hydra community to socialize and test Emergency Standards procedures
- Consider pre-negotiating confidentiality agreements prior to invoking the Emergency Standards development activity

Conclusion

GridEx 2011 provided an opportunity to test the Electricity Sub-sector's crisis response plans, and evaluate the community's current readiness to respond to a cyber incident. The exercise also served as an opportunity to enhance collaboration and strengthen industry security processes and capabilities. Participants considered the exercise a successful training event that delivered substantial return on time and resource investments. To reinforce the value of sector-wide exercises, entities expressed a strong interest in participating in future GridEx engagements.

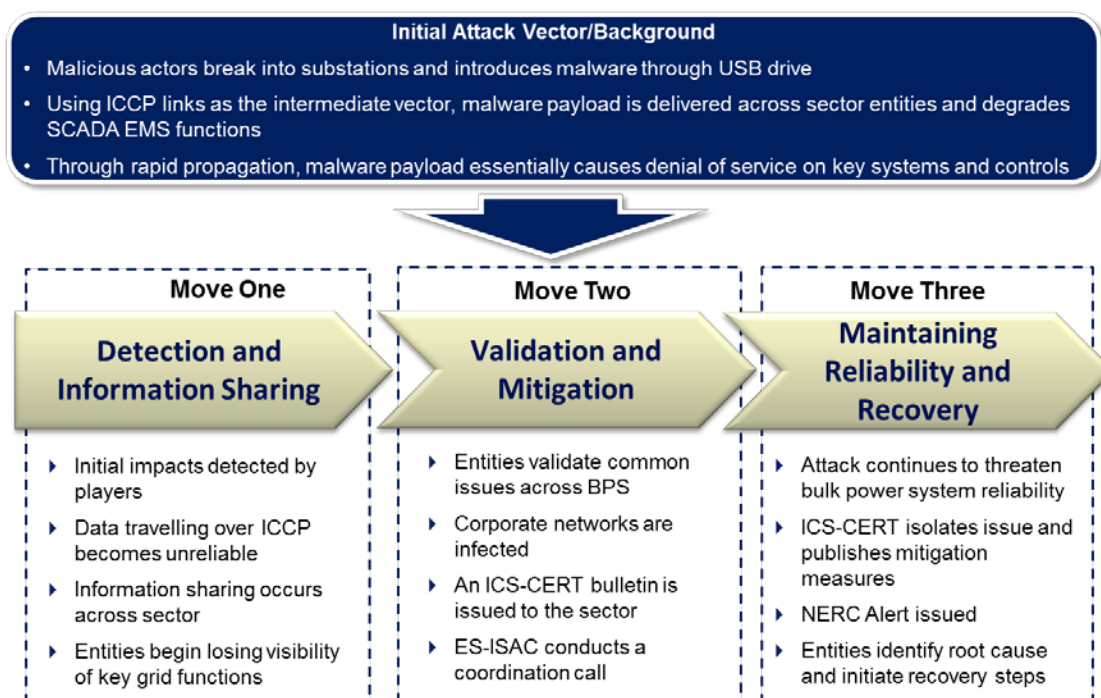
The Electricity Sub-sector successfully achieved its objectives and identified key areas for further exploration during both the planning and execution phases of GridEx. Participants worked together during planning and exercise play to strengthen relationships, evaluate cyber incident response plans, and expose issues for improvement. After participating in GridEx, the sub-sector is better positioned to effectively participate in future industry and government sponsored exercises like GridEx 2013, Cyber Storm 4 and the National Level Exercise 2012. In addition, the Electricity Sub-sector is taking steps to address the findings to enhance its ability to respond to a coordinated cyber attack on the BPS.

Appendix A: GridEx Scenario Narrative

Introduction

The NERC GridEx scenario was crafted to achieve exercise objectives and fully engage the broad GridEx stakeholder set. The scenario had broad relevance among players, promoted coordination during the exercise, and highlighted urgent issues facing the sector. A malware attack with attributes of an advanced persistent threat was developed to realize desired scenario conditions and achieve exercise objectives. The malicious code (malware) compromised the industrial control system (ICS) environment and eroded inter-party trust relationships. As players detected anomalous activity and lost control of systems, they began to share information, coordinate response measures, and mitigate impacts. While the technical feasibility of the scenario was vetted by experts across industry, some liberties were taken to ensure broad applicability and the achievement of exercise objectives.

Scenario Concept Diagram



Overview of Initial Attack Vector and Malware Behavior

Although the exercise began with the assumption that malicious code had already infiltrated critical cyber assets within the BPS, a back-story or “ground truth” was crafted to establish the scope and impacts of the attack.

Prior to Move One of exercise play, a motivated adversary with a desire to cause disruption to the power grid had devoted significant resources to developing malware that attacked grid functions. The code leverages communications protocols as an intermediate attack vector to deliver malicious code across the North American bulk power system. Once delivered, the

malware corrupted core systems and their functions. The malware required two vital pieces of information to work – network address information and operator credentials. The attacker gained unauthorized access to several substations and back-up control centers (BUCC) and inserted a low profile data device between the keyboard and the computing workstations in these locations to capture administrative credentials and other sensitive data for later use in crafting malware.

Upon introduction, the sophisticated malware sensed anti-virus/anti-malware products in use, maintained a small footprint, and supported numerous operating system-based payloads that could be launched from within the master payload located at one of the drop locations. The malware communicated with other copies to share information in a ‘mesh’-based methodology so that if any one node was discovered, the communications of that node did not reveal nodes belonging to other cells. The malware was designed to run adjacent to main reporting processes and opened ports usually assigned to permitted functions (so that intrusion detection was not triggered), transferred the binary or mapping information, and shut down. A number of hidden binaries were included in the master binary. These additional binaries were small applications designed to run inside existing critical systems. The malware also had the ability to travel from the ICS environments to the corporate network through trusted links. Once there, the worm sought to find egress points out of the network.

Exercise Phases/Moves

The exercise was structured around three phases or “moves” that simulated three discrete blocks of time. To simulate the passage of time, a notional 24 hours passed between Move One and Move Two, and 48 hours passed between Move Two and Move Three. Each move was initiated by new information that updated players’ situational awareness and understanding of the current environment.

Move One (T-Zero): Detection and Information Sharing

In Move One, sector entities and organizations began observing abnormal activity in their operational environment. Network operations were sluggish and an overall system slow-down was detected. Operators observe traffic resets and remote terminal unit (RTU) scans fail to complete. It appears that timing relationships and signals are corrupted, endangering the electricity sector’s remote assets.

The malware has created plausible changes in unit outputs that remain within the unit’s operating limits. Impacted entities begin to identify alternative means of relaying data, including verbal communications and other manual approaches. Entities also consider deploying manpower to substations to address reliability concerns with remote assets. While the source of the issues is not yet understood, IT staff begins forensics measures and attempt to clean systems. Utilities, BAs and RCs share information on the conditions and validate a common pattern of suspicious conditions across the BPS. Players become suspicious of communications protocol traffic and begin to focus on this channel as a source of abnormalities. Meanwhile, market dispatch issues arise due to data anomalies complicating the arrangement of imported power (interchange). The disturbance and current conditions necessitate entities to issue Electric Emergency Incident and Disturbance Reports (OE-417) to the appropriate authorities.

As Move One concluded, entities continued to lose visibility and experienced difficulty managing load. An RCIS bulletin revealed that cyber tampering at major utilities' key locations had been detected.

Move Two (T+24 hours): Validation and Mitigation

In Move Two, entities continued to experience reliability concerns as summer peak demand exacerbated load balancing issues. ICS-CERT released a bulletin that stated that the imbedded malware was observed attempting to exploit a C2 channel (command and control) within some entities. The egress was detected through analysis of entity network logs. In coordination with ICS-CERT, the FBI announced to the sector the probability of malicious intent to disrupt the power grid. Entities continued to report severe conditions and reliability concerns through RCIS bulletins while coordinating with Regional Entities and authorities. Some failover and back-up systems were inoperable, which forced many entities to initiate manual operations. This process severely taxed resources of RCs, BAs and other Regional Entities. The scenario affected several key calculations and forced some utilities to abandon market activity. Other small utilities that failed to detect the C2 egress experienced intermittent outages in their regions. ICS-CERT, in coordination with the FBI, gathered a fly-away team to engage in further analysis and forensics. Entities also experienced issues with their corporate LAN and other supporting systems, as the malware appeared to have vectored to the corporate network. Network functions were sluggish and DNS resolution was unreliable. Outage management/GIS systems are compromised, corrupting distribution functions among some entities. To conclude Move Two, the ES-ISAC scheduled a sector coordination call to review impacts, provide guidance, and coordinate a response.

Move Three (T+72): Maintaining Reliability and Initiating Recovery

Move Three began with a media report, chronicling the coordinated attack, grid conditions and response activities. By the start of Move Three, the ES-ISAC, ICS-CERT, FBI, DOE, and FERC shared information frequently. ICS-CERT analyzed malware and published near-term identification and mitigation measures and the NCCIC continued to serve as a coordination point for government agency interaction and information sharing. Entities worked with their anti-virus and control system vendors to obtain patches. A NERC Alert was issued to provide malware information and eradication steps to the community to clean systems and restore functionality. At the conclusion of Move Three, fragile grid reliability was achieved, but with significant inefficiencies.

Appendix B: Areas for Future GridEx Improvements

GridEx participants completed After Action Questionnaires, which provided both substantive input on response activities and feedback on exercise mechanics, logistics, and support. While the success and strengths of the exercise were widely acknowledged by planners and players, NERC noted several areas for improvement for future grid security exercises. Below are key themes that emerged from the after action process:

- **Broader Representation from Industry:** While GridEx featured comprehensive participation from across the sub-sector, some entity counterparts were not engaged. This forced some participating utilities to simulate interactions, rather than exercise real-world communications paths. During the planning of future exercises, the NERC planning team, in coordination with participating entities, should target and recruit previously absent organizations (such as key Independent System Operators and Reliability Coordinators) to increase realism. More extensive participation of business units within entities would also strengthen GridEx engagements.
- **Enhanced Inject Distribution and Sequencing:** Players remained occupied with exercise injects throughout GridEx, but planners observed some distribution gaps. While some exercise periods featured a rapid succession of injects, others periods provided far fewer updates to players. A more consistent inject release process could steady the overall exercise battle rhythm. In addition, revisions to pre-established inject content or timing should be more clearly communicated to players in advance to alleviate confusion during exercise play.
- **More Secure Media Viewing:** The mock news reports provided realistic updates to the evolving scenario that enhanced player engagement, but video distribution mechanisms can be improved. Several organizations block YouTube Internet Protocol addresses, forcing planners to rely on the file transfer protocol (FTP) site to access the video. Although the FTP site was an effective alternative, download speeds were slow, and some players were delayed in viewing videos. A more secure host that can stream high-resolution video should be identified for future exercises.
- **Clearer “Rules of Engagement” for Player Conduct:** While the C/E Handbook provided planners a detailed understanding of GridEx, some participants were unclear on exercise

expectations and guidelines. For example, players did not know if they should file OE-417s, or if the filing was considered a notional activity. In the future, more straightforward guidance can be provided on expected player activities and actions. Additionally, more accurate assessments about anticipated time commitment for C/Es and players will assist participating organizations in proper resource allocation.

- **Improved Player Directory:** The Player Directory served as the key resource for enabling exercise coordination and information sharing during GridEx. Despite efforts to capture all player details prior to exercise play, some contact information was not initially available. An enhanced directory tool, potentially available online, could allow real-time additions and revisions to the player directory.
- **Arrange for training credit:** Some exercises, like GridEx, award training credits for full participation. Training credit serves as an incentive for active participation among players and satisfies organizational commitments. Planners should ensure the credit requirements are clear, and necessary preparation is undertaken in advance of the exercise.

Appendix C: GridEx Terminology

- **2500 Inject:** Injects that do not have a discrete time release designation. They are transmitted as needed based on actual exercise play, and are often sent when players are not responding appropriately to previous injects.
- **Controller/Evaluators:** C/Es observe and record key actions and interactions within their organization. They also plan and manage exercise play. C/Es provide key data to players and may prompt or initiate certain player actions to ensure exercise continuity. Any changes that impact the scenario or affect other areas of play must be coordinated through the C/E, who will coordinate with the Exercise Control (ExCon). All C/Es will be accountable to the ExCon. They also evaluate and provide feedback on a designated functional area of the exercise. C/Es assess and document participants' performance against established industry crisis response plans and exercise evaluation criteria, in accordance with Homeland Security Exercise and Evaluation Program (HSEEP) standards. They have a passive role in the exercise and only note the actions of players; they do not interfere with the flow of the exercise.
- **ENDEX:** Official end of exercise (1300 EST Thursday, 17 November, 2011).
- **Exercise:** An instrument to train for, assess, practice, and improve performance in prevention, protection, response, and recovery capabilities in a risk-free environment; can be used for: testing and validating policies, plans, procedures, training, and interagency agreements; training personnel; improving interagency coordination and communications; identifying gaps; and identifying opportunities for improvement.
- **Exercise Control:** ExCon is responsible for conducting the exercise. They will send injects to the C/Es. ExCon can be reached out to at any point during the exercise. ExCon is also to be copied on all outgoing mail during the exercise.
- **Hotwash:** Report findings and lessons learned to C/Es and/or Lead Planners as applicable.
- **Inject:** The information that the player actually receives from ExCon; could be a phone call, email, screenshot, error message, etc.; an observable event of the larger exercise scenario.
- **Monitor/Respond Player:** Monitor Responder players view selected segments of the exercise. They do not play in the exercise, and do not perform any control or evaluation functions. Monitor Responders can receive injects, exercise internal processes, and participate in coordination calls.
- **Players:** Players are participants who have an active role in responding to the simulated cyber attack and perform their regular roles and responsibilities during the exercise.

Players will fully engage in the exercise, responding to all injects and participating in coordination calls.

- **Planning Team:** Exercise support staff includes individuals who are assigned administrative and logistical support tasks during the exercise.
- **STARTEX:** Official start of exercise (0930 EST Wednesday, 16 November, 2011).

Appendix D: Acronym List

- **ACE** - Area Control Error
- **AGC** - Automatic Generation Control
- **C2** - Command and Control
- **CCA** - Critical Cyber Assets
- **ED** - Economic Dispatch
- **EMS** - Energy Management System
- **ES-ISAC** - Electricity Sector Information Sharing and Analysis Center
- **FEP** - Front End Processor
- **FTP** - File Transfer Protocol
- **GIS** - Geographic Information System
- **ICS-CERT** - Industrial Control Systems Cyber Emergency Response Team
- **IDS** - Intrusion Detection System
- **IP Address** - Internet Protocol Address
- **LAN** - Local Area Network
- **LFC** - Load Frequency Control
- **MS-ISAC** - Multi-State Information Sharing and Analysis Center
- **NCCIC** - National Cyber and Communications Integration Center
- **OE-417** - Electric Emergency Incident and Disturbance Report

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NERC Seeks Talented Professionals

Compliance

FERC Endorses Find, Fix and Track Initiative

The North American Electric Reliability Corporation (NERC) is very pleased the Federal Energy Regulatory Commission (FERC) endorsed the Find, Fix and Track approach.

“NERC is encouraged by FERC’s approval of our filings using the new compliance initiative format,” said Gerry Cauley, president and chief executive officer at NERC. “By identifying and resolving issues that do not pose a serious risk to the reliability of the bulk power system, more resources can be focused on violations that do pose a serious risk to the grid.”

In the order, FERC notes that:

- The vast majority of FFTs filed are satisfactory.
- Reduction of the burden to address minimal risk issues is important.
- Violations are final 60 days after submittal unless there is cause to open for review.
- Violations must be of minimal risk to the bulk power system. (FERC may revisit this after the year status report filing.)
- Registered Entities must certify that violations are remediated.
- Registered Entities must be identified in filings, except for cases of critical infrastructure protection violations.
- Random surveys will be conducted each year by FERC to gauge program performance.
- NERC and Regional Entities may propose mechanisms to identify and remove unnecessary or redundant requirements within reliability standards.

While additional guidance is provided in the order, NERC is pleased that the past six months of FFT filings give FERC confidence in how NERC and the Regions are implementing the initiative.

Within the six filings, more than 425 violations have been remediated. FFT reflects a risk-informed approach that recognizes not all possible violations are equal and should not be treated in the same manner. The new initiative was designed to handle compliance issues more efficiently; focus on issues posing a more serious risk to reliability; streamline administrative paperwork; and continue to encourage self-reporting and mitigation.

NERC looks forward to working with the Regional Entities, stakeholders and FERC to further improve the FFT process. ■■■

Critical Infrastructure

NERC Enhances Cybersecurity Efforts through ES-ISAC

The North American Electric Reliability Corporation (NERC) has enhanced the Electricity Sector-Information Sharing and Analysis Center (ES-ISAC) structure and information sharing capabilities to better address the ever-changing threats to North America’s bulk power system.

NERC formally established an ES-ISAC division to focus on ES-ISAC activities and functions. Tim Roxey, formerly director of Risk Assessment and Technology, was promoted to chief cybersecurity officer.

The ES-ISAC team focuses on enabling sector-wide cybersecurity coordination, trust and engagement among participants, as well as rapid analysis and information sharing with the sector and its partners. As the chief cybersecurity officer, Roxey leads the ES-ISAC team and manages all aspects of the ES-ISAC. He also serves as the point of contact for NERC stakeholders.

“Analysis and dissemination of timely information regarding security threats to the North American bulk power system is an essential role of NERC,” said Gerry Cauley, president and chief executive officer at NERC. “This type of coordination and collaboration among the industry and key government partners is

paramount to the continued success of the electric reliability organization.”

The ES-ISAC also is improving information sharing capabilities through different mechanisms, such as the ES-ISAC website (www.esisac.com) and through collaboration with other sectors and the Department of Homeland Security’s National Cybersecurity and Communications Integration Center.

A new portal for members only has been added to the ES-ISAC website that allows members to securely share and collaborate with industry peers. Expansion of the portal is planned this year to include collaboration zones and to establish bi-directional information sharing capabilities.

“The new ES-ISAC division will bring a degree of clarity and focus to the two primary ISAC functions - information sharing and analysis of emerging threats and vulnerabilities to the bulk power system,” Roxey said. “This structural alignment of ISAC functions, along with the tools of the enhanced ES-ISAC portal and a legal framework for information sharing, will open new opportunities for the ES-ISAC to help enhance grid reliability.”

These resources will significantly enhance the information sharing capabilities; however, resources alone will not resolve all roadblocks to trusted information sharing. NERC recognized the potential conflict to managing both the compliance function and the information sharing function and, to remove this barrier, drafted the [ES-ISAC Policy Statement](#), which was approved by the NERC Board of Trustees on February 9. The policy prohibits the ES-ISAC from acting as a conduit to compliance and enforcement functions, and confirms the confidentiality of non-regulatory information sharing among industry.

This commitment by NERC, combined with the ongoing initiative to develop and enhance a private portal, creates a collaborative and transparent information sharing environment that will enable industry to defend against the growing threats of the 21st century.

DOE Releases Risk Management Process Guideline for Second Comment Period

The [Electricity Subsector Cybersecurity Risk Management Process](#) (RMP) guideline was developed by the Department of Energy (DOE), in collaboration with the National Institute of Standards and Technology (NIST) and the North American Electric Reliability Corporation (NERC).

The primary goal of the voluntary guideline is to describe risk management and is intended to be used by organizations responsible for the generation, transmission, distribution, and marketing of electric power, as well as supporting organizations such as vendors.

The guideline has undergone a second quality review and technical edit and was reposted for comment on March 3. The 30-day public comment period ends April 5, which gives the core development team approximately three weeks for final edits and publication in April.

Members of industry and utility-specific trade groups were included in authoring the guidance designed for the Electricity Subsector. For more information, contact [Brian Harrell](#).

NERC Grid Exercise Increases Cybersecurity Readiness; Identifies Enhancements to Improve Security

The North American Electric Reliability Corporation (NERC) completed its after-action review of the 2011 grid security exercise, GridEx 2011. The review identifies key findings and recommendations for improving the electric industry’s cybersecurity programs.

More than 75 organizations, including utilities and U.S. and Canadian governments, participated in the exercise, which was designed to validate the readiness of the industry to respond to a cyber incident, strengthen the crisis response functions of utilities, and provide input for internal security program improvements.

“GridEx provided a realistic environment for organizations to assess their cyber response capabilities,” said Brian Harrell, manager of critical infrastructure protection standards, training and awareness at NERC. “Through the exercise interaction, participants forged and strengthened relationships across the cybersecurity community.”

Key findings and recommendations in the [2011 NERC Grid Security Exercise After Action Report](#) include:

Entities possess effective cyber incident response plans, but updates to protocols and guidelines and additional training would enhance preparedness. NERC will develop and raise cybersecurity awareness by conducting focused training opportunities to promote and emphasize incident response and recovery.

Significant horizontal communication occurs across the industry, but vertical information sharing to NERC and government agencies is limited due to compliance concerns. NERC will coordinate with the Critical Infrastructure Protection Committee Information Sharing Task Force to develop guidance and outreach strategies that create a more secure and trusted environment for information sharing.

NERC’s Electric Sector-Information Sharing and Analysis Center (ES-ISAC) and Situation Awareness teams effectively coordinated the central communication function, but expediting the FERC review of the NERC alert process, refining call mechanics, and activating the ES-ISAC portal will further enhance the response role.

Utilities took appropriate steps to secure the grid. NERC will facilitate and support the development of physical security guidance in partnership with the industry and other North American security organizations.

The NERC emergency standards process should be coordinated to avoid interference with core incident response activities at the entity level. NERC and the industry will review enhancement options to support

the overall goal of ensuring bulk power system reliability.

NERC will continue to work with stakeholders and government agencies to further clarify findings from GridEx through root causes analysis, and policy enhancements and improvements. ■■■

Information Technology

New webRegistry System Open for Registration

The North American Energy Standards Board (NAESB) and Open Access Technology International, Inc. (OATI) announced that the new electric industry registry – webRegistry – is open for registration. Participants must complete an application form, which must be approved before industry applicants can access the system.

The new system – formerly called Transmission System Information Network (TSIN) – is the central repository for information to support commercial, schedule and transmission management operations in North America.

Click [here](#) for webRegistry application and [here](#) for the OATI website. For assistance, contact [OATI support](#). ■■■

Reliability Risk Management

First Human Performance Conference Well Attended by Industry

More than 200 participants representing more than 100 companies in the United States and Canada attended NERC’s *Improving Human Performance on the Grid* conference on March 27-29 in Atlanta. The conference included presentations and panel discussions from the Department of Energy, the Department of Transportation and the National Transportation Safety Board.

The conference focused on best practices for reducing error in operations on the bulk power system through

a collaborative, interactive forum. A training session on cause analysis and developing a human performance program also took place.

Presentations from the conference will be posted on the NERC website, under the Event Analysis tab by the end of April, and a webinar is being planned for the 3rd quarter to discuss next steps. For more information on human performance, contact [James Merlo](#). ■■■

Standards

Update from Project 2008-06: Version 5 CIP Cybersecurity Standards

The draft CIP cybersecurity standards, version 5 provide several benefits compared to previous versions and NERC's Project 2008-06 Cyber Security Order 706 standards drafting team continues work on improving the Version 5 with input provided by stakeholders during the formal comment and initial ballot period that ended January 6. The drafting team reviewed and discussed stakeholder-provided comments and incorporated that input to improve upon Version 5's framework for supporting a culture of security.

The Version 5 standards also present strategic advantages; chiefly, to close out FERC Order No. 706. In addition, Version 5 aligns to essential reliability functions and provides significant flexibility to entities in adapting requirements to individual operations.

Version 5 represents a systems-based approach to standards, which provides an opportunity to implement solutions and tailor security based on function, connectivity, risk and impact. That flexibility represents a significant transition from the "in or out" demarcation for applying requirements in Versions 1-4 of the standards, as the drafting team has been able to structure Version 5 in a way that more finely tunes the applicability of each requirement based on connectivity, impact, and other characteristics.

This latest version is an experience-based set of standards. It is the first opportunity for the industry to evaluate, consider and incorporate lessons learned

from implementation and audit of Versions 1-3, and the requirements aim to provide clearer emphasis on the required results. The next draft of Version 5 is expected to be posted for formal comment and successive ballot in early April.

Standards Progress in Addressing Regulatory Directives

Since the Federal Energy Regulatory Commission (FERC) certified NERC as the Electric Reliability Organization in 2006, 50 Orders containing 721 directives related to NERC Reliability Standards have been issued. With the help of numerous industry volunteers, NERC continues to make progress in addressing these regulatory directives through the reliability standards development process.

Standards-related directives are addressed when they are assigned to an applicable standards development project, which is then initiated based on a project prioritization that was established by NERC's Standards Committee, approved by the NERC Board of Trustees, and documented in the annual [NERC Reliability Standards Development Plan](#).

The majority of standards-related directives (435) were issued in 2007, with an additional 123 issued in 2008, 62 issued in 2009, 67 issued in 2010, and 32 issued in 2011. Of the 721 directives issued since 2007, NERC has addressed and filed 58 percent with FERC. In addressing the remaining directives, NERC has made significant progress by focusing on directives with the greatest impact on reliability. In 2011 alone, NERC addressed and filed 118 directives with FERC, and plans to address 156 in 2012.

The NERC Standards Report, Status and Timetable for Processing Regulatory Directives will be filed soon with FERC.

Modification to Definition of Protection System

On February 3, FERC issued [Order No. 758](#) that approved an Interpretation of PRC-005-1. Concurrent with Order 758, FERC issued another order ([Docket No. RD11-13-000](#)) that approved a modification to the

definition of Protection System. The current definition of a Protection System, as defined in the NERC Glossary of Terms, is: “Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.” The modified definition of Protection System is:

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

The modified definition of Protection System becomes effective on April 1, 2013.

Each responsible entity subject to PRC-005-1 is required to modify its protection system maintenance and testing program description and basis documents, as required by Requirement R1, to reflect the revised definition of protection system by April 1, 2013.

Each responsible entity is required to implement any new or additional maintenance and testing, as required by Requirement R2, by the end of the first complete maintenance and testing cycle described in the entity’s program description and basis documents.

Accessing Standard and Interpretation Project Statuses

Stakeholders can stay informed about NERC standards and interpretations projects by participating in webinars, attending workshops, following the weekly standards bulletin, and keeping track of NERC announcements.

In addition to these tools, stakeholders can refer to the [Standards Under Development page](#) on the NERC website for comprehensive status reports on all active standards and interpretations projects. In the links at

the top of the Standards Under Development page, links to the [Standards Progress Report](#) and the [Status of Outstanding Interpretations](#) can be found. Both documents are updated at least monthly and list each active standard or interpretation project, a general description of that project, logistical information about the project (team leadership, target finish date, etc.), and a detailed status report that explains what the standard drafting team is working on, its next planned steps and meetings, and any issues the team is facing.

Stakeholders are encouraged to take advantage of these tools to get up-to-date information on active projects.

Utility Hosts CIP Peer Sharing Event

PPL Corporation hosted a CIP peer sharing event February 15-16. More than 140 industry peers from 26 different companies attended the event, which was designed to bring peers together to discuss PPL’s approach to assembling and packaging the required evidence to demonstrate compliance to the CIP standards.

PPL’s eastern generation fleet, located in the ReliabilityFirst region, was one of the first generator owner/generator operators in North America to undergo a full CIP audit in May 2011. The audit scope covered five registered entities and the review of more than 100 Technical Feasibility Exceptions. It was completed in 3.5 days with no violations and 12 data requests prior to and during the audit.

The CIP Peer Sharing Event agenda included individual PPL presentations for each CIP standard delivered by the staff members responsible for assembling the evidence package for each standard. Corporate Risk Solutions, under contract with several Regions to perform NERC CIP audits, also delivered two presentations on CIP issues from an auditor’s perspective.

In addition to the peer sharing, participants received electronic copies of two PPL files. One included the CIP evidence citations (appropriately redacted) used

by PPL for the May 2011 audit. The second file provided an editable framework of CIP that peers can tailor for their CIP evidence packages. Look for these files on the NERC website after the NERC Standards and Compliance Workshop in San Diego on April 16-18.

Register Now for NERC Standards and Compliance Workshop; Updated Agenda

Registration is still open for NERC's Reliability Standards and Compliance Workshop April 16-18 in San Diego. In-person registration is open until April 2, and webinar registration is open until April 9. Click [here](#) to register and [here](#) to view the updated agenda

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 Rodriguez](#) with questions regarding the vacancies. ■■■

Filings

NERC Filings to FERC

(click on the link for full filing)

March 15, 2012

[Informational Filing of NERC in Response to Order No. 754](#)

NERC submits an Informational Filing of the North American Electric Reliability Corporation in Response to Order No. 754 that includes a report on the reliability issues concerning system protection associated with the Commission-approved

interpretation of Requirement R1.3.10 of Reliability Standard TPL-002-0. *Docket No. RM10-6-000*

March 16, 2012

[Errata to NERC Glossary of Terms Definition of IROL](#)

NERC submits an errata changing the term "Cascading Outages" in the FERC-approved NERC Glossary of Terms definition of Interconnection Reliability Operating Limit (IROL) to "Cascading outages." *Docket No. RM06-16-000*

March 23, 2012

[Comments in Response to Notice of Proposed Rulemaking on Standard for Business Practices for Interstate Natural Gas Pipelines](#)

NERC Comments of the North American Electric Reliability Corporation in Response to Notice of Proposed Rulemaking on Standards for Business Practices for Interstate Natural Gas Pipelines and in support of the modified Wholesale Gas Quadrants ("WGQ") Standard 0.3.14, which changes the parties to whom pipelines are required to provide notification of operational flow orders and other critical notices. *Docket No. RM96-1-037*

March 30, 2012

[NERC 2012 Standards Report, Status, and Timetable for Addressing Regulatory Directives](#)

NERC submits the second annual Standards Report, Status, and Timetable for Addressing Regulatory Directives summarizing the progress made and plans for addressing the standards-related directives. *Docket No. RR12-_-__*

NERC Filings in Canada, click [here](#)

(click on the link above for full filing)

March 1, 2012

[Notice of Filing of BES Definition](#)

NERC submits a notice of filing regarding the Revised Definition of "Bulk Electric System" in the NERC Glossary of Terms Used in Reliability Standards.

[Notice of Filing of BES Exception Procedure](#)

NERC submits a notice of filing regarding the 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"). ■■■

Careers at NERC

Manager, Internal Audit and Corporate Risk Management

Location: Atlanta

[Details](#)

Manager of Bulk Power System Awareness

Location: Atlanta

[Details](#)

Data Management System Specialist

Location: Washington, DC

[Details](#)

Compliance Enforcement Analyst

Location: Washington, DC

[Details](#)

Senior Compliance Engineering Analyst

Location: Washington, DC

[Details](#)

Engineer of Organization Registration and Certification

Location: Atlanta

[Details](#)

Compliance Auditor

Location: Atlanta

[Details](#)

CIP Compliance Auditor

Location: Washington, DC

[Details](#)

CIP Compliance Manager

Location: Washington, DC

[Details](#)

Senior Reliability Engineer (Relay)

Location: Atlanta

[Details](#)

Senior Reliability Engineer (EMS)

Location: Atlanta

[Details](#)

Project Manager

Location: Atlanta

[Details](#)

Attorney

Location: Washington, DC

[Details](#)

Senior Statistician

Location: Atlanta

[Details](#)

Standards Adviser

Location: Atlanta

[Details](#)

Auditor Training Specialist

Location: Atlanta

[Details](#)

Technical Training Specialist

Location: Atlanta

[Details](#)

Standards Development Adviser

Location: Atlanta

[Details](#) ■ ■ ■

NERC News

April 2012

Headlines

NERC Participate in Technical Conference on Geomagnetic Disturbances and the Grid

NERC Names New General Counsel

Standards and Compliance Workshop in San Diego Well Attended by Industry

Compliance

Risk-Based Compliance Method Key Discussion at Workshop

Critical Infrastructure

Save the Date for NERC's 2012 Grid Security Conference

Joint Product on Physical Security Project

Reliability Assessment and Performance Analysis

NERC, EPRI Release Open Source Code to Analyze Geomagnetically Induced Currents

New webE-GADS Application Launched to Support Mandatory GADS

Standards

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Standards Committee Meeting Highlights

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CIP Version 5 Posted; Version 4 Approved

Make Plans to Attend

Standard Drafting Team Vacancies

NERC Filings

Documents Filed with FERC and/or Canada during the Month

Careers

NERC Seeks Talented Professionals

Headlines

NERC Participate in Technical Conference on Geomagnetic Disturbances and the Grid

Experts from the North American Electric Reliability Corporation (NERC) participated in a technical conference focused on geomagnetic disturbances and their effect on the bulk power system today.

Gerry Cauley, president and chief executive officer, and **Mark Lauby**, vice president and director of Reliability Assessment and Performance Analysis, participated in two-panel discussions hosted by Federal Regulatory Energy Commission (FERC) staff.

The conference focused on the risks and impacts from geomagnetically induced currents on transformers and other equipment on the bulk power system, as well as options for mitigating the risks.

Follow these links to technical conference testimony for [Cauley](#) and [Lauby](#). For a comprehensive look at geomagnetic disturbances and the grid, read NERC's interim report [2012 Special Reliability Assessment: Effects of Geomagnetic Disturbances on the Bulk Power System](#). The report outlines the most likely outcomes, while offering short- and long-term recommendations for industry.

NERC Names New General Counsel

NERC President and Chief Executive Officer Gerry Cauley is pleased to announce that Charles A. Berardesco will join NERC as the new general counsel, effective July 2.

Prior to joining NERC, Berardesco served as Constellation Energy's senior vice president, general counsel, corporate secretary and chief compliance officer, as well as chief legal adviser to Constellation's Board of Directors. Berardesco joined Constellation in January 2003 and served in a number of different roles at the company.

"Charlie brings his outstanding legal and corporate background, especially in compliance and regulatory activities, to NERC," Cauley said. "His knowledge and

expertise will help further develop the legal strategies and policies of the electric reliability organization."

Prior to joining Constellation Energy, Berardesco practiced law and served in senior executive positions for nearly 20 years, including vice president, general counsel and corporate secretary at Fusara, a consortium of AIG, Kemper and Prudential; and as senior vice president, general counsel and corporate secretary at HCIA, a publicly held health-care information company.

"I am honored to be joining NERC's talented team and support the essential mission of North American grid reliability," Berardesco said. "We are at an important juncture in the development of an overall national energy policy and NERC's role and responsibilities have never been more relevant or more important."

David Cook, NERC's current general counsel, will remain at NERC in a part-time capacity after July 2 to assist with the transition. Rebecca Michael will continue to play a key role and provide continuity in legal operations.

Standards and Compliance Workshop in San Diego Well Attended by Industry

More than 200 stakeholders attended NERC's Spring Standards and Compliance Workshop on April 16-18 in San Diego – either in person or via webinar. During the workshop, attendees heard presentations from standards, compliance, enforcement, reliability assessment, human performance and training staffs, along with several stakeholder presentations and keynote remarks from NERC Board of Trustees member Ken Peterson.

Participants are encouraged to provide an evaluation of the workshop. The site will remain live through May 2. Click on the electronic surveys: [Day One](#), [Day Two](#), and [Day Three/General Workshop Questions](#). All resources from the San Diego workshop will remain available on [the standards workshop webpage](#). (See *Compliance* section below for more workshop information). ■■■

Compliance

Risk-Based Compliance Method Key Discussion at Workshop

At the recent Standards and Compliance workshop in San Diego, the Compliance department provided a presentation on the [Risk-Based Compliance Method Initiative](#) (slide 75). This initiative includes several projects, such as the Entity Assessment Template and Reliability Standard Audit Worksheet (RSAW) development. As program developments occur, announcements will be shared with industry.

In conjunction with the RSAW development project, two RSAWs have been posted for comments on the Compliance site: COM-002-2a: Communication and Coordination, and PER-005-1: System Personnel Training. The RSAWs vary slightly in terms of format, as NERC is in the process of determining, with industry input, the most effective way to present the RSAW.

NERC appreciates the feedback from the Committees, Regions and registered entities on the prioritization list of potential CAN issues. With industry input, NERC Compliance categorized the 26 CANs into three groups of high, medium and low, and the results are posted online in the CAN Status and Priority List. Also on the list are four new potential CAN issues for industry to prioritize. Entities may provide prioritization input via the CAN Process Appendices 2 or 3, the Industry Prioritization Form or CAN Comment Form (specific to one CAN), located on the CAN page under Compliance Application Notices Processes and Tools.

There are currently four CANs posted for comment on the Compliance website. Comments are due May 7 for CAN-0034 EOP-002 R1, IRO-001 R2 and TOP-001 R1 Use of Authority Letters and CAN-0038, PER-002 R4 Training Hours. As CIP Version 5 comments are due May 25, NERC has provided additional time to comment on the two CIP CANs. The comments are due June 4 for CAN-0019 CIP-007 R3 Implementation of Software Security Patches and CAN-0023 CIP-005 R3, and CIP-006 R6 Logging System Failures. ■■■

Critical Infrastructure

Save the Date for NERC's 2012 Grid Security Conference

NERC will host its second Grid Security Conference (GridSecCon 2012) on October 16-18 in San Diego. The conference will bring together industry and government security professionals to discuss grid security concerns, trends, and best practices.

The first day of the conference will be dedicated to training with courses taught by Idaho National Laboratories, SANS Institute and Lofty Perch. The following two days will cover topics including:

- Emerging industrial control system security issues.
- Social engineering and spear phishing.
- NERC's Critical Infrastructure Protection Standards.
- Electromagnetic pulse threats.
- Electricity Sector-Information Sharing and Analysis Center.
- Security crisis management.

Registration for this event will begin in June. For more information, contact [Brian Harrell](#).

Joint Product on Physical Security Project

NERC has initiated a project called the Joint Product on Physical Security (JPPS). A team of experts from the United States and Canada, including representatives from NERC, the Royal Canadian Mounted Police, Public Safety Canada, the Federal Bureau of Investigation and the Department of Homeland Security, will collaborate with Electricity Sub-sector representatives to develop an industry whitepaper. This whitepaper will identify current threats and physical measures considered "best practices" to assist the electric industry security programs.

Also detailed will be current physical threats facing the sector (such as copper theft, insider threats and individual attacks); recommended physical security measures deemed effective throughout the electricity Sub-sector; and detection, response and mitigation

measures that support physical security best practices.

Through case studies, this document will demonstrate the necessity and cost effectiveness of implementing physical security and mitigation recommendations throughout the industry. The document will be available to industry decision makers as a voluntary tool. The document will be updated annually to reflect the ever-evolving threats to the industry and the latest physical security and mitigation measures to address those threats.

NERC will continue to provide expertise and leadership to this project, keep participants posted on the progress, and provide the opportunity for feedback prior to publication. For more information, please contact [Brian Harrell](#). ■■■

Reliability Assessment and Performance Analysis

NERC, EPRI Release Open Source Code to Analyze Geomagnetically Induced Currents

In a joint effort, the North American Electric Reliability Corporation (NERC), Department of Energy (DOE) and the Electric Power Research Institute (EPRI) developed a simulation tool for the electric industry to analyze geomagnetically induced currents (GIC) on their systems.

The software, which is an open-source code, was developed as part of NERC's ongoing efforts to identify high-impact, low-frequency risks, such as the impact of geomagnetic disturbances effects on the bulk power system.

"One of the key findings in NERC's geomagnetic disturbance report is the bulk power system planners and operators require more tools to simulate the impacts of GIC on the grid," said Mark Lauby, vice president and director of Reliability Assessments and Performance Analysis at NERC. "This open-source software is a starting point toward equipping the

industry with the information needed to ensure continued bulk power system reliability."

The GIC simulation program is capable of performing N-phase modeling, meaning the analysis is not limited to three-phase systems. Additionally, the program's interface allows users to define circuit models, execute the functions of the program and implement algorithms that interact with the simulator. This allows users to dynamically change circuit parameters and modify input, enabling long-term (hours or days) analysis of GMDs.

The GIC program uses earlier research that integrates GMD modeling into power flow analysis and was conducted at the University of Illinois at Urbana-Champaign as part of the DOE-funded Power Systems Engineering Research Center (PSERC) Future Grid Initiative.

"Industry needs to know if and when the bulk power system and equipment are vulnerable to the effects of GMD," said Richard Lordan, senior technical executive at EPRI. "This tool calculates the geomagnetically induced currents used to perform system and equipment analysis."

The GIC simulation portion of the program was added to EPRI's existing Open Source Distribution System Simulator (OpenDSS), which is a comprehensive electric power system simulation tool that supports frequency domain analyses.

The tool has been used for more than a decade in support of various research and consulting projects requiring system analysis. Improvements, such as GIC simulation capability, have advanced the use of the program. The OpenDSS software tool has been designed to be scalable so it can be modified to meet future needs.

Additionally, DOE, EPRI and industry are expanding the GIC monitoring system nationwide to produce additional measurements used to test and improve the accuracy of the tool's models. Further, this network of GIC monitors will fortify industry's ability

in forecasting GICs and support operating action to mitigate their effects on the bulk power system.

NERC released the [*2012 Special Reliability Assessment: Effects of Geomagnetic Disturbances on the Bulk Power System*](#) in February. The report takes a comprehensive look at multiple, complex issues to evaluate GMD effects; outlines the most likely outcomes; and offers short- and long-term recommendations for industry. The GMD report is the second of four ongoing efforts identified in the 2010 [*High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*](#) report, which also includes the spare equipment database report, which has been released; and two upcoming reports from task forces focused on cyber attack and severe impact resilience.

To download EPRI's OpenDSS, visit <http://sourceforge.net/projects/electricdss/>. A Wiki containing supplementary documentation, the latest information, hints and tricks is available at <http://electricdss.wiki.sourceforge.net/>. For technical support, contact [Roger C. Dugan](#).

New webE-GADS Application Launched to Support Mandatory GADS

NERC, in conjunction with Open Access Technology International, Inc. (OATI), launched a new data collection system on April 24 that collects information for measuring and monitoring the contributions of electric power plants to the reliability of the bulk power system. The new system – webE-GADS - will support mandatory reporting guidelines for conventional generating units registered to meet NERC's Reliability Standards with a nameplate rating of 50 MW and larger that began January 1. This equates to approximately 92 percent of the total installed capacity in the NERC footprint.

The new web-based system will facilitate the data collection process on a quarterly basis. This system will provide NERC access to vital information needed to evaluate electric generation of the bulk power system in North America, and support an integrated

view of events when coupled with transmission system availability data.

Before the system's launch, 433 reporting generator owners and generator operators were given live tutorials over the course of four training sessions that covered operational data reporting, unit registration and maintenance, and frequently asked questions. To date, 805 companies have registered with webE-GADS. NERC expects all companies meeting the mandatory requirements to have their 2012 first quarter data submitted by June 24

For more information on webE-GADS, contact [GADS support staff](#). ■■■

Standards

Revised Definition of Adequate Level of Reliability Posted for Comment

The Adequate Level of Reliability Task Force was formed in May 2011 under the auspices of the NERC Standing Committees Coordinating Group, which comprises the chairs and vice chairs of NERC's standing committees. The task force is addressing concerns expressed by the NERC Board of Trustees, the MRC and stakeholders that NERC's current definition of Adequate Level of Reliability (ALR) needs reassessment to ensure that the definition supports and helps define NERC's mission to ensure reliable operation of the bulk power system.

The task force goal is to develop a definition of ALR that encompasses NERC's responsibility to ensure reliable planning and operation of the bulk power system, and to identify and define reliability objectives and performance characteristics that drive what system planners and operators do on a day-to-day basis.

On April 25, the task force posted a draft definition document, a draft technical report, a discussion paper on risk tolerance, and a mapping document comparing the proposed ALR objectives with NERC's reliability

principles. The documents are available for industry comment through June 25 on the [ALRTF webpage](#).

Standards Committee Meeting Highlights

On April 11-12, the Standards Committee had its quarterly in-person meeting at the Florida Reliability Coordinating Council's offices in Tampa. In addition to its usual discussion of active standards development projects and coordination with regulatory authorities, the Standards Committee considered a cost effectiveness proposal being field tested by the Northeast Power Coordinating Council, and discussed the work and early recommendations of the Standards Process Input Group (SPIG).

FERC, NERC and stakeholders have expressed an interest in a process to determine effectiveness and implementation costs of proposed standards. In response, NPCC drafted a Cost Effective Analysis Proposal (CEAP) that currently is being field tested. The CEAP introduces one assessment for feasibility and another to determine estimated industry-wide cost impacts and potential reliability benefits of NERC standard requirements.

As the process continues, it will be analyzed, adjusted and considered for continent-wide use. The ultimate goal is to incorporate, within NERC's standards process, a mechanism to inform stakeholders of proposed industry cost impact and to provide an opportunity for suggestions of alternate methods to achieve equally effective reliability goals and objectives that may result in less cost. The CEAP will be posted for industry review mid-May.

In February, the Member Representative Committee was asked to begin a working group to provide policy input and recommendations for specific improvements to the existing NERC Reliability Standards development process. The SPIG's work began in March and its members reached out to the industry for input and feedback on four key topics: quality of standards (including process and product); timeliness; efficiency and effectiveness; and the importance and significance of meeting American National Standards Institute requirements. The SPIG

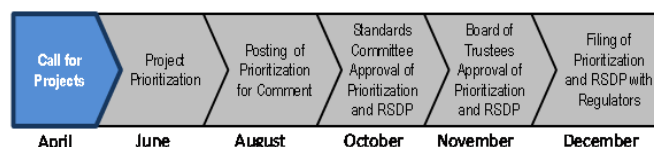
has gathered valuable insight on these issues and compiled a report consisting of five recommendations. The MRC, along with the Standards Oversight and Technology Committee, will discuss these recommendations and determine next steps at their May 8 meeting.



The Standards Committee also took advantage of this meeting to bid farewell to the longtime NERC coordinator of the Standards Committee, Maureen Long (left). Long was celebrated with an ice cream social and an official version of one of her famous gold stars.

NERC Requests Standards Development Project Candidates

NERC is developing the 2013-2015 Reliability Standards Development Plan (the Plan), which will provide status updates for projects in development, identify the next projects scheduled for initiation, designate projects for further research, and catalog all proposed projects for future development.



As the first part of this effort, NERC is soliciting the industry for project candidates. This is an important way for stakeholders to get involved in NERC's determination of its next steps for standards development. To offer suggestions, please submit via email to [Andy Rodriguez](#) using the new [Suggestion Form](#) no later than May 11.

For a description of projects already being considered in the planning process, please see the [2012-2014 Plan, Appendix 4](#).

CIP Version 5 Posted; Version 4 Approved

A second draft of Version 5 Critical Infrastructure Protection Cybersecurity Standards was posted for a

parallel formal comment and successive ballot through May 21. The strategic advantages of Version 5 include the shift to a results-based standards format, the systems-based approach that considers impact and connectivity in applying requirements, the responsiveness to lessons learned from implementing and auditing previous versions of the CIP standards, and the increased flexibility to tailor solutions to individual operations. Those materials are available on the [Project 2008-06: Cyber Security Order 706 webpage](#).

On April 19, FERC approved NERC's Version 4 of the CIP Cybersecurity Standards, agreeing with NERC's justification for the bright-line criteria used to identify Critical Assets in Version 4. While the posted second draft of Version 5 has proposed to extend Version 3 until Version 5 is implemented in lieu of implementing Version 4, such an approach has not yet been approved by the industry. The approval date and implementation plan for Version 4 establishes an enforcement date in the United States of April 1, 2014.

The approval of Version 4 is a significant milestone in meeting the remaining directives in FERC's Order No. 706, and NERC will continue to develop information for the industry on the coordination among Version 3, Version 4, and Version 5 of the CIP Cyber Security Standards.

Make Plans to Attend

NERC Standards will host a State of Standards webinar from 1-5 p.m. July 26, and will coordinate with compliance staff for a second workshop October 23-25 in Atlanta. More details will be released closer to the event dates.

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 2010-13.2 Generator Relay Loadability

Seeking an individual with experience in generator protection systems from the FRCC or MRO region and either the cooperative or merchant electricity generator sector.

Please contact [Andy Rodriquez](#) with questions regarding the vacancies. ■ ■ ■

Filings

NERC Filings to FERC

(click on the link for full filing)

April 12, 2012

[Informational Filing in Response to FERC Order No. 758 - Interpretation of Protection System Reliability Standard](#)

NERC submits a schedule regarding the development of certain technical documents including the identification of devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation and a schedule for the development of the changes to the standard that NERC stated it would propose as a result of the above-referenced documents. Docket No. RM10-5-000

April 16, 2012

[Limited Request for Clarification, or, in the Alternative Rehearing of the March 15, 2012 FFT Order](#)

NERC submits a limited request for clarification or, in the alternative, rehearing, of the FERC order issued on March 15, 2012. Docket No. RC11-6-001

April 24, 2012

[Errata to Petition for Approval of FAC-003-2](#)

NERC submits an errata to the Petition for Approval of Proposed Reliability Standard FAC-003-2—Transmission Vegetation Management correcting a typo in the Compliance section of the standard. Docket No. RM12-4-000

April 27, 2012

[Errata to Petition for Approval of Proposed Texas Regional Entity Reliability Standard IRO-006-TRE-1](#)

NERC submits errata to the Petition for Approval of Proposed Texas Regional Entity Reliability Standard IRO-006-TRE-1 to correct an incorrect reference to an effective date. *Docket No. RD12-1-000* ■■■

Careers at NERC

Manager, Internal Audit and Corporate Risk Management

Location: Atlanta

[Details](#)

Manager of Bulk Power System Awareness

Location: Atlanta

[Details](#)

Compliance Enforcement Engineering Specialist

Location: Washington, DC

[Details](#)

Manager of (NOP) Notice of Penalty Development

Location: Washington, DC

[Details](#)

Compliance Enforcement Analyst

Location: Washington, DC

[Details](#)

Engineer of Organization Registration and Certification

Location: Atlanta

[Details](#)

CIP Security Specialist

Location: Washington, DC

[Details](#)

Senior Reliability Engineer (Relay)

Location: Atlanta

[Details](#)

Senior Reliability Engineer (EMS)

Location: Atlanta

[Details](#)

Manager of Electric Reliability Organization Enterprise Projects

Location: Atlanta

[Details](#)

Attorney

Location: Washington, DC

[Details](#)

Standards Adviser

Location: Atlanta

[Details](#)

Auditor Training Specialist

Location: Atlanta

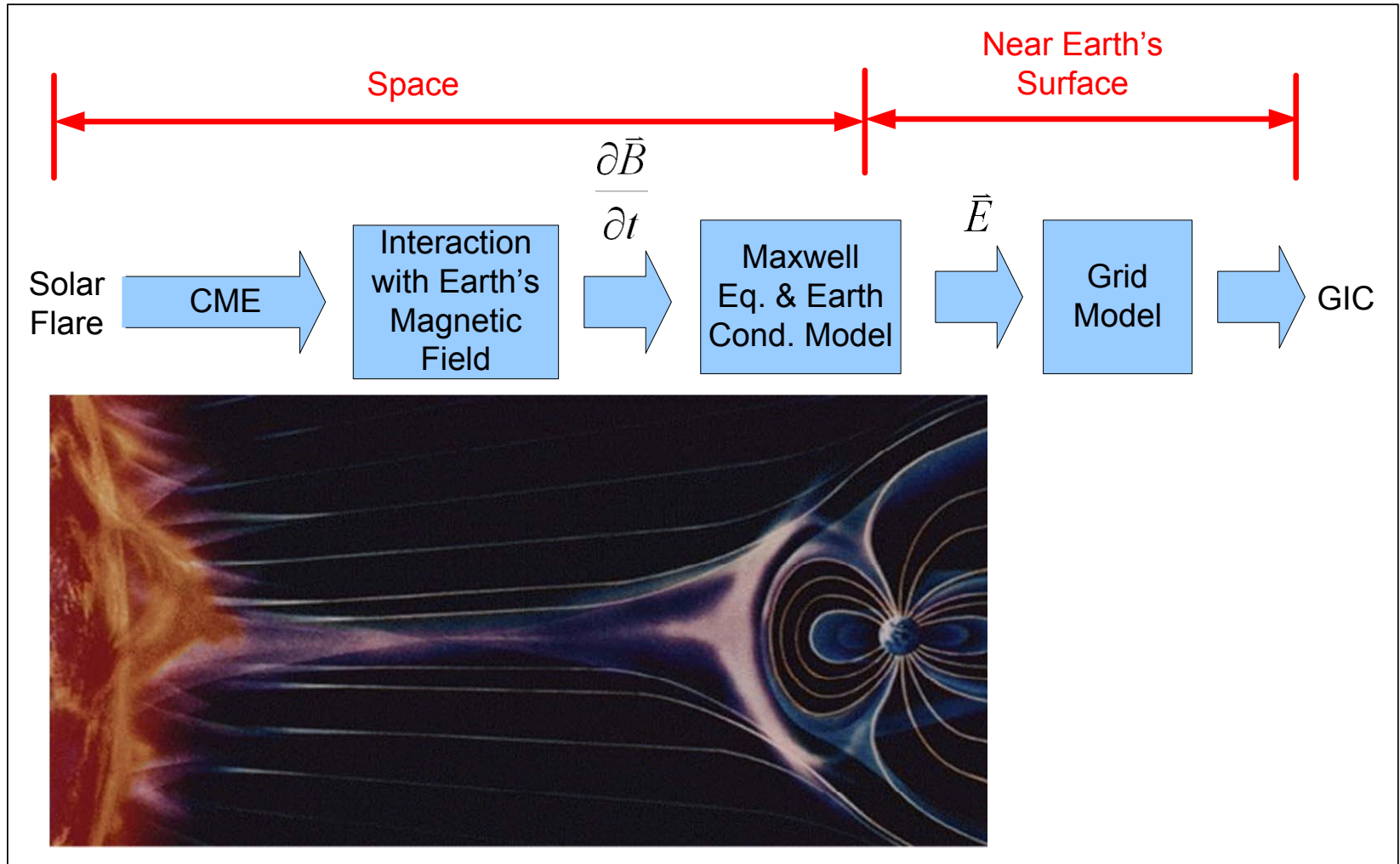
[Details](#)

Standards Development Adviser

Location: Atlanta

[Details](#) ■■■

Geomagnetic Disturbances



- Approved by the NERC Board of Trustees and publicly released on February 29, 2012
- Identifies grid vulnerability from GMDs and highlights solutions to mitigate bulk power system
- Comprehensive view at multiple, complex issues:
 - Evaluated GMD effects on equipment and the system
 - Identified the most likely failure mode and possible outcomes
 - Outlined short- and long-term industry recommendations



Major Conclusion

- Highest likelihood of GMD is loss of reactive power

Major Conclusion

- Challenge will be to maintain supply of reactive power

Major Conclusion

- Some transformer types may be damaged or lose remaining life

- Update operating procedures
 - Existing NERC recommendations available [here](#) in May 2010
NERC GMD Advisory
- Provide planning and operator tools
- Develop education and research
- Review the need for enhanced NERC Reliability Standards

- Develop additional open source tools and models to develop GMD mitigation strategies
- Assess various potential equipment vulnerabilities
- Improve tools and procedures for System Operators to manage GMD impacts
- Education and information exchange between researchers and industry
- Develop enhanced NERC Reliability Standards as needed
- Improve information Interfaces with other players

- Issues?
- Questions?
- Ideas looking forward?

Thank you!

**NPCC Task Force on Coordination of Operation
Final Meeting Minutes
Tuesday, January 17, 2012-11:00 AM to 5:00 PM
Wednesday, January 18, 2012-8:00 AM to 3:00 PM
Hyatt Harborside Hotel
Boston, Ma.**

In attendance:

Dwayne Basler*	Northeast Utilities
Jim Castle*	New York ISO
Dave Daley* (Chair)	NBSO
Leonard Kula*	IESO
Daniel Lefebvre*	TransÉnergie
Richard Mailhot*	TransÉnergie
Jerry Mosier (1/17)	Northeast Power Coordinating Council
John Norden (Vice-chair)*	ISO-New England
Paul Roman	Northeast Power Coordinating Council
Michael Schiavone* (telephone)	National Grid
David Stanford*	Nova Scotia Power
Dan Taft	Con Edison
Paul Tremblay*	Hydro One
Wes Yeomans (1/18)	NYISO
Gerry Dunbar (telephone)	Northeast Power Coordinating Council
Jacques Audet (1/18 telephone)	NBSO
Ahmed Maria (1/18)	IESO

* Voting TFCO member or proxy.

1. Administrative Items

a. Determination of Quorum

All 10 TFCO voting members were in attendance.

b. Approval of the “Draft for Comment” Minutes of the Task Force on Coordination of Operation Meeting of December 6, 2011

The draft minutes were approved and will be issued and posted on the NPCC web site.

c. Roster Changes

No changes are needed.

d. TFCO 2012 Meeting Dates and Locations

There was a change to the time of one of the 2012 TFCO meetings. The Syracuse meeting will now be held on Wednesday, May 16 all day and Thursday, May 17 8 AM EDT to noon. The TFCO, RCC, CO Working Group and NERCORS and OC meetings scheduled for 2012 are listed in Exhibit 1.

2. Off-Peak High Transmission Voltages and Voltage Control Practices in NPCC

Wes Yeomans presented some observations regarding recent conditions in New York in which 345 kV circuits have been switched out of service to control high voltages. The locations with the most significant concern are on the 345 kV path between the north-central and southeastern parts of the New York system. The need to control these high voltages became more common during late 2010. Factors that contribute to the occurrence of the high voltages include: low system loads, low cross state transfers, Leeds SVC outage and reduced imports. Flows on the Central East Interface have been as low as 700 MW. Some operating actions normally used to control voltage usually used before taking lines out of service include:

- Switching out shunt capacitors
- Switching in shunt reactors
- Requesting generators to absorb reactive power
- Adjusting transformer taps
- Bringing on generators with reactive output control capability

NYPA is presently attempting to justify the need to add another 345 kV shunt reactor. A 150 Mvar shunt reactor at Coopers Corners 345 kV station would be expected to reduce the voltage by about 6 kV.

The other TFCO RCs were asked whether they have switched out high voltage lines to control high transmission voltages and to describe some of their voltage control practices and voltage limits.

New Brunswick—Switching circuits out to avoid high voltage has not been used but is being considered. Several factors make circuit switching more likely, especially for the northern portion of the system. The factors include: outage of the Eel River SVC in Fall 2010, paper-pulp plant shutdowns, two thermal generating units being shutdown in northern New Brunswick, and more wind generation be used. The wind generators provide little Var support.

The pre-contingency voltage limit is 105% and the post-contingency limit is 110%. There is no specific time requirement to return to 105% following a contingency.

New England--There have been conditions with potential high voltages and circuits (lines or cables) have occasionally been taken out of service to reduce charging current to avoid high voltages. Equipment warranties for some 345 kV facilities require that 362 kV be considered the high voltage limit for pre- or post-contingency conditions.

The primary voltage control action has been to commit generation and control Var outputs to control system voltage. This is done, if practical, prior to switching out circuits. There are procedures in place for the voltage control practices with emphasis on areas remote from heavy load areas and in the Boston area (due to underground cables).

Ontario—500 kV circuits have been switched to prevent high voltages but this is not a common practice. Also, 230 kV circuits in the Toronto area have been switched but this is not considered a desired voltage control practice. The desired alternative is to replace switches with heavy duty ones and to use automated control. Voltage control actions are similar to what is done in New York. Pump storage generators are not placed in service for voltage control purposes.

Quebec—The Quebec system includes many long 735 kV and 315 kV lines with very large charging current. Many of the station locations are very distant from generators so that using generators for voltage control is not a practical means to control voltage. The main voltage control practice involves switching of shunt reactors and use of SVCs. There is a total of about 25,000 Mvar of shunt reactor capability on the Quebec system and 20 SVCs/synchronous condensers. In the past TransÉnergie had been able to justify part of the cost for addition of these shunt reactors because line losses are significantly reduced when all 735 kV lines remain in service compared to the higher losses that would result when lines are taken out of service.

The voltage control range used is $\pm 3\%$. Automatic post-contingency switching of shunt devices is in place for post-contingency voltage control. It is not fast enough to enhance transient stability performance but it is sufficient for voltage control.

In Quebec 735 kV lines are sometimes removed from service for light load conditions at times when the other controls are not sufficient.

Summary

All NPCC systems have at times have had high voltage control concerns.

Action Item: This item on voltage control practices will be kept on TFCO agendas for future meetings. The CO-8 Working Group will also be requested to address this topic at the February 1-2 meeting.

3. Operating Conditions

a. Report by each RC--each Area by exception

New Brunswick—There have been no significant recent operating issues. An anticipated concern involves system operation during the outages taking place in Maine for the testing and phase-in of the new 345 kV line addition (New England MPRP Project). Testing will take place prior to expected commercial operation in June 2012. Testing for the return to service of the Point Lepreau nuclear generator will begin in June 2012.

Nova Scotia—At times the wind generation level has reached 25 to 30% of the total Nova Scotia load. There have been times when generation has been curtailed.

New England—Highlights include:

- On December 19, 2011 the OP-4 Operating Procedure was used when there was a 300 MW deficiency in 10-minute operating reserve. The deficiency was mainly due to outages of the Kleen Energy, Brayton Point 1 and Granite units. OP-4 steps that called for demand response measures and resulted in a 400 MW reduction in demand. The end user reduction was very close to the reduction expected.
- Minimum generation emergencies occurred during the Christmas-New Year's holiday period. There was very close coordination with the entities supplying or delivering gas to the gas-fired generators prior to and during the cold temperatures days experienced this winter.
- ISO-New England coordinated the LIDAR testing work being done by the New England Transmissions Owners.

New York—The New York Transmission Owners are conducting LIDAR testing to evaluate ratings on transmission lines so that conductor sag adjustments are made and ratings are maintained. The NYISO is coordinating this work and staggering outages in different geographical areas to prevent operating problems.

Since natural gas generation has grown to be a bigger portion of the New York capacity mix and the gas generators use interruptible gas supply contracts, the electric-gas industry coordination procedures are being examined and may need to be enhanced. With capacity prices lower than past years many of the 79 MW Non Utility Generators in New York have non-competitive heat rates and many are now being retired.

Con Edison—Lake Erie Circulation has affected how Con Edison determines the optimal tap settings on the Con Ed-PSEG Phase Angle Regulator taps. Testing is needed on the Con Ed dual fuel units to ensure minimum oil burn is maintained.

Ontario—Highlights included:

- Temperatures have been well above normal this winter and there have been surplus power issues that have required dispatching nuclear units.
- Bruce Nuclear Units G1 and G2 will be returning to service during the first and third quarters of 2012, respectively, after long-term layoff and refurbishment. All eight Bruce units will be back in service for a short time period (about 6,000 MW), however, shortly after Bruce Units G3 and G4 will be taken out for a similar refurbishment.
- During 2012 approximately 200 MW per month of wind generation is scheduled to go into service.
- There are still six coal units left in service but all coal generation is scheduled to be gone by the end of 2014.
- Two new 500 kV lines are being added to support full generation at the Bruce Nuclear Complex.
- The BP76 230 kV Beck-Packard circuit voltage regulator is scheduled to go into service by December 2012).

Quebec— Highlights included:

- Temperatures have been above normal this winter and demands have been below forecast so far. Highest demand so far was about 35,500 MW on January 16 (-16°C temperature).
- All lines connected at Laurentides station are now in service.
- A new SVC was added in the Montreal area in December 2011.
- In December 2011 series compensation was added to two 735 kV lines that head south from James Bay.

b. Arizona-California Blackout

This blackout is still under investigation and information on it is considered confidential. Some information release is expected by April 15, 2012. Gerry Cauley has requested that the NERC Operating Committee take a close look at the event and is emphasizing that lessons learned must be developed and shared.

Other events that will also be looked at closely are Texas cold weather and the late October winter storm in New England.

4. NPCC Regional Reliability Reference Directory 1, “Design and Operation of the BPS”

TFCO members reviewed the operations criteria portion of the latest version of Directory #1. In 2009 when Directory #1 was first developed it was a direct translation from the NPCC A-2 Basic Criteria document with some associated NPCC “B” and “C” documents added as appendices. In 2010 and 2011 the CP-11 Working Group made revisions to the Directory to update the content and to place it into requirements language, which would

satisfy Directory Process Phase II. The language in the operations criteria portion of D#1 was specifically developed by Pat Doran in order to ensure that the draft NERC style criteria in that section properly reflects the intent of the existing criteria. Also, as part of the Phase #2 review of Directory#1 the initial CP-11 draft removed language that was duplicative with any NERC standards requirements. The TFCO review involved Section 5.5, Requirements R1 through R.11. The CO-8 Working Group had reviewed section 5.5 at their November 2011 meeting and had suggested changes to R7, R9.1 and R10. Those changes were considered in the TFCO review of Directory #1. TFCO suggested changes:

R1: Remove “*sufficiently in advance of the outage*”.

R2: End R2 after “*list*”.

Reword R3: “*Transmission Operator(s)/ Transmission Operator(s) shall coordinate outages on facilities which impact inter-Reliability Coordinator Area reliability to minimize the time that the facilities are out of service.*”

R4 was Ok and no changes were needed.

R5: “Each Transmission Operator shall develop *and operate* to System Operating Limits (SOL’s)...”

Remove “*and operate*” from above and in R8.

The previous suggested revisions from the CO-8 Working Group were accepted:

R7: Each Transmission Operator shall operate to Normal Transfer Capability *unless it is unable to meet Normal Transfer Capability* at which time it shall operate to Emergency Transfer Capability.

R9.1 Assess the status of the bulk power system and adjust transfer levels, if necessary, to prepare for the next contingency, *immediately after the occurrence of a contingency*.

R10 Each Transmission Operator shall take all measures necessary, including the pre-contingency disconnection of firm load when Emergency Transfer Capability is exceeded or to avoid exceeding Emergency Transfer Capability.

The Working Group CO-08 believes that more clarification is required.

Appendix A, "Definition of Terms":

Applicable emergency limits - These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc.

Emergency limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes.

The Working Group CO-08 believes that more clarification is required.

General TFCO Concern

Section 5.5 requires operating to System Operating Limits (SOLs) and TFCO members disagreed with using this reference in an NPCC Directory. This is not a defined NPCC term and SOLs are not applied consistently throughout NERC. TFCO would prefer instead to use the previously-used reference to operate to ***normal or emergency transfer capability***.

It also appeared that Section 5.5 had requirements that are the same as requirements in some NERC TPL and TOP standards. The TFCO understanding has been that Directories should not duplicate NERC standard content. This still needs to be checked

General Principles for Revision of Directory #1 Operations Content

- The content should contain the requirements that go above and beyond what is included in the existing NERC standards and not duplicate any NERC requirements.
- The NERC standards (primarily the TPL and TOP standards) should be carefully screened to compare the NERC content versus the existing Directory #1 operations criteria content.
- There must be clarification from NPCC staff regarding exactly what system equipment the operations criteria apply to (BES or BPS).
- The draft Directory #1 general requirements sections (Sections 1 through 4) should be compared to the similar general requirements in all the other existing Directories to establish consistency among all these Directories. There should be consistency.
- The references to “Notes” in the operations criteria content should be removed but all the content retained.
- All references to SOLs should be removed and they should be replaced with the previously existing ***normal and emergency transfers*** references, as appropriate.

5. NPCC Regional Reliability Reference Directory 6, “Reserve Sharing Groups”

Directory #6 was posted for comment from September 8, 2011 to October 24, 2011. There was one comment from IESO posted in the review process and one other separate comment was received from the NYISO. TFCO reviewed the comments and drafted responses.

The NYISO comment indicated:

The NYISO is suggesting that NPCC add an approval process for the RCC to approve RSG Agreements prior to implementation. The RCC is in the position to review agreements that could have an impact on the NPCC Membership, while at the same time checking to ensure that the agreement is consistent with the Directory #6 document as approved by the RCC. This is consistent with other approval processes of the RCC, including the approval of Area Transmission Reviews as submitted by the area, with compliance obligations as laid out in Directory #1. The NYISO proposes the addition of Requirement R 2.1 as follows:

R2.1 NPCC Members of an RSG shall obtain Reliability Coordinating Committee (RCC) approval prior to going into effect, including any future changes developed by the RSG.

Response

TFCO did not object to providing a recommendation for approval for RCC consideration, however, some members expressed some concern with RCC review of the reliability impact methodology, as that may require a more detailed review than what is normally done by the RCC.

IESO comments included:

If the intent is to eventually migrate this document to a Phase II Directory, then we question the need for this "intermediate phase" of Directory 6, and suggest that this draft version be revised to adopt the Phase II directory structure to save the time and effort needed to develop two revisions to achieve the desired outcome -a Phase II Directory 6.

Response

The Directory is already in Phase II format. Earlier thinking for Phase II format had been to require measurements and compliance process requirements but that is no longer required as part of Phase II format.

Requirements R2 and R4: The two requirements are intended to achieve the same outcome, i.e., that the RSG provides their RSG Agreement, with supporting information, to the Regional Entity for review before it is implemented. To have an R4 separated from R2 makes it look like they are intended to achieve different outcomes. We therefore suggest combining R2 and R4. TFCO members also noted that ATR/SAR should be spelled out.

Response

TFCO considers R2 and R4 to provide two distinct requirements and agreed that it is better to keep them separate. TFCO agrees with the addition of a third option "Other comparable methods that produce the required quantitative reliability estimate."

Requirement R5.18: This is a commercial arrangement which does not belong to a directory that stipulates reliability requirements. We suggest removing this requirement.

Response

TFCO does not agree with removing this requirement. This requirement is related to Requirement 6 that indicates the amount of reliability product shared and could serve as a check on how much reserve BAs would be willing to share.

Requirement R.19: This requirement should be stipulated in Directory #5 and not in an RSG agreement.

Response

TFCO does not agree with removing this requirement.

Action Item: The responses on the Directory #6 comments will be posted on the NPCC web site.

TFCO members also noted that Requirement 5.5 wording should use “shall” instead of “must”.

NPCC staff will post the TFCO responses on the NPCC web site and Directory #6 will be provided to the RCC at their March 1 meeting to seek RCC approval to send the Directory to the membership for an approval vote.

6. NPCC Regional Reserve Sharing Standard

Recently, NERC has provided flexibility for the Regions when deciding to develop Regional Standards among 4 topics, including reserve sharing. Contingent on the progress of a NERC continent-wide standard and the identification of any reliability gaps the Regional Standards Committee (RSC) has authorized the development of a NPCC regional standard on reserve sharing (NPCC-BAL-002-001). The first step is to name and confirm members of the regional reserve sharing standard drafting team. The members nominated include: Francis Monette (TransÉnergie), Mike Potishnak (ISO-New England), Dave Robitaille (IESO), Kun Xiong (Ontario Power Authority), Dave Daley (NBSO) and Dave Mahlmann (NYISO). Lee Pedowitz is the NPCC staff representative of the drafting team.

7. Bruce Type I SPS #112

Ahmed Maria provided a presentation on the proposed modification to the Bruce Type I SPS #112. Previous modifications had been approved by TFCO in 2008. In the spring of 2008, the IESO submitted to NPCC a request for classification of the following

enhancements to the Type I Bruce Special Protection System (#112 in the NPCC list of SPS):

1. Monitoring of additional contingencies at 500 and 230 kV;
2. Cross tripping of 115 kV circuit 2S2;
3. Reactivation of idle load rejection selections; and
4. Tripping of wind farm facilities.

The purpose of the existing SPS is to reject Bruce generation for a contingency that trips a 500 kV Bruce transmission outlet circuit to avoid voltage or transient stability. The amount of generation armed for rejection is dependent on the generation level and the status of the Bruce 500 kV transmission outlets. This allows higher generation levels at Bruce. New SVCs are being added at Detweiler and Nanticoke. The proposed modification involved the addition of a SMOS system (SVC Maximum Output System). This modification will provide the capability to maximize the Mvar output of the Nanticoke and Detweiler SVCs for a short period of time following a contingency. The TFCO approved the operability of the SPS with this new modification.

NPCC staff and the chairman will provide a letter indicating TFCO approval to the Task Force on Coordination of Planning.

8. Revised C-17, “Procedures for Monitoring and Reporting Critical Operating Tool Failures” Document

Jacques Audet, the CO-10 chair, discussed the status of the C-17 document. It had been posted for comment from June 6 to July 22, 2011 and CO-10 was seeking TFCO approval to repost the document with revisions. The CO-10 working Group addressed the posted comments received and changed the document based on those comments and on comments received from TFCO. Jacques reviewed all changes to the document:

- Added C-17 review of EMS failures for TOs,.
- Section 2, item 2) Backup Power Supply
*The loss of any backup supply element that results in an interruption to power supply for critical operating tools, Backup supply includes **Uninterruptible Power Supplies and emergency generation** .*
- Section 3, item 1--To avoid duplication in reporting, an initial Appendix A shall not be required if the reporting entity has submitted a Brief Report required for the NERC Event Analysis Process. This updates the document based on the Event Analysis Process.

TFCO approved the revised C-17 document for reposting for comment on the NPCC web site. **CO-10 and NPCC staff will prepare a cover letter and repost the document for comment on the NPCC web site.**

9. Review of Disturbances

a. CONVEX Loss of EMS Event (September 2, 2011)

Dwayne Basler reported on this event. This partial failure of the EMS occurred on September 2, 2011 at 22:27 EDT. It resulted in complete loss of SCADA for 35 minutes. It involved memory being fully consumed on one of two EMS systems with the study application located on the other system. To mitigate the problem memory was increased and the user interface was modified so that for a failure on one of the system it would switch over to the working system.

There is no need for additional TFCO action on this and the TFCO review is considered closed.

b. United Illuminating SCADA Loss of Monitoring Functionality (September 18, 2011)

On Sunday September 18, 2011, The United Illuminating Company (UI) experienced a loss of Ethernet based RTU communications from approximately 08:30 through 22:51. At the time stale data was being displayed to the UI Operations Center and that left operators without visibility of the transmission system (>100 kV) in the UI territory. However, at the time of the failure event Northeast Utilities had the capability to monitor the UI facilities and could provide control actions for any system problems. A complete loss of SCADA, control or monitoring functionality for 30 minutes or more is a Category 2 Event.

This event was reviewed thoroughly in the Event Analysis process and lessons learned from it included:

- It is beneficial that Transmission Operators and Transmission Owners install a “heartbeat monitor” alarm to detect stale or stagnant data.
- A periodic evaluation should be conducted of the mismatch thresholds for State Estimator alarming specific to each operating area, such that it will allow for the optimum sensitivity while minimizing false mismatch alarms.

There were no violations during the event. There is no need for additional TFCO action on this and the TFCO review is considered closed.

c. Quebec Laurentides Events (October 14 through November 10)

Richard Mailhot explained the event. Laurentides substation is in the Quebec City vicinity and has 735 kV connections to the Levis, Micoa and Jacques-Cartier Stations. It includes 735 kV, 315 kV and 230 kV busses. The event started with the failure of a 315 kV circuit breaker. Some circuit breakers were out of service pre-contingency and several 315 kV breakers opened to clear a circuit breaker

fault. Initially it was not clear why the breaker failed. Transfer limits were not affected and no load was lost during the event.

Following the initial event there were several single phase faults occurred on 5 other 315 kV breakers at Laurentides on different days. The suspected reason was high humidity and failure of the air dryer system. All of the 315 kV breakers have a common air dryer system. Weather was not severe, with temperatures at about 0° C at the time. There is an alarm for the air dryer system, however, it was later determined that the alarm for the air dryer system was inoperable.

A lesson learned was make improvements to the alarm on the air dryer system for multiple breakers that share an air dryer system to provide an alert when the alarm system fails.

d. Lake Road Event (December 19, 2011)

At 07:15 on 12/19/2011, three Lake Road generators (combined output of 474 MW) tripped due to the unintended activation of an SPS. To mitigate an SOL following the trip of a remote 345 kV breaker at 06:48, the Operators needed to either shut down the three Lake Road generators or switch out of service a 345kV transmission line. During the switching of the 345 kV transmission line, the SPS was not disarmed as required, resulting in the activation of the SPS. The three generators were given permission to restart at 08:10 when system conditions allowed their return to service. No SOL, IROL or firm load loss occurred as a result of the actions above.

There were no violations during the event. There is no need for additional TFCO action on this and the TFCO review is considered closed.

e. Copper Thefts and Vandalism

It was agreed that the copper thefts are quite numerous and do not generally pose bulk power system reliability risks and it is not necessary for TFCO to review them, unless they end up with significant system impact.

10. NPCC Regional Reliability Reference Directory #5, "Reserve"

Changes suggested from TFCO at the December 6, 2011 meeting had been included and Directory #5 was posted for Comment on December 16, 2011. The comment ending date for the directory was January 30. By January 18 no comments were posted, however, there had been an e-mail question to NPCC outside of the posting for review process from Drew O'Keefe at Northeast Utilities:

Was the intent that a Claim 10 (ten minute reserve) audit should require a unit to run for 1 hour? ISO-NE is contemplating this change in part based upon the below wording. We would prefer not having to burn that much fuel, obviously.

5.13 Sustainability of Operating Reserve Synchronized reserve, ten-minute reserve, and thirty-minute reserve available to a Balancing Authority, if activated, shall be sustainable for at least one hour from the time of activation. Balancing Authorities shall determine their sustainability requirement for reserve on Automatic Generation Control (AGC) based on their ability to achieve compliance with relevant standards, with due consideration of their operating characteristics.

TFCO members agreed that the Directory does not directly require that a test be performed in which the generator would have to run for an hour to demonstrate the capability for Directory #5. The requirement is that it be able to run for an hour. There are separate testing requirements in Directories #9 and #10.

Radial Source Contingency White Paper—The white paper had been reviewed by TFCO at the December 6 meeting and some additional revisions were made. **The white paper with the revisions that were made based on the TFCO review at the December 6 meeting will be provided to the CO-8 Working Group for a final review at their February 1-2 meeting. The white paper should be finalized at that meeting.**

The concepts indicated in the white paper will need to be checked versus Appendix 4 content. **Mike Potishnak will make modifications to Directory #5, Appendix 4 to incorporate the white paper concepts. Mike will provide this for review at the CO-8 meeting.**

Review of Performance during Recent SAR Events

Mike Potishnak discussed some of the problems noticed during the analysis of past Simultaneous Activation of Reserve events. Examples include late notifications, ACE overshoots, late entry of SAR share schedules and SAR shares entered as ramp changes rather than step schedule changes.

11. Bulk Electric System (BES) Definition

The NERC definition of Bulk Electric System had been approved by NERC stakeholders in late November 2011. The main industry concerns have been the generation threshold level and distinguishing distribution vs. transmission facilities. There is a Standard Authorization Request to establish Phase 2 of the BES project. It has been posted for informational purpose and will later be posted for comment.

12. Update of NPCC Facilities for Notification Lists

Paul Roman reported that all TFCO and CO-8 members and alternates now have the ability to access the NPCC Facilities for Notification list on the NPCC web site at a restricted spot on the CO-8 page. Members need to log on to the NPCC web site using their unique username/password rather than the general NPCC member login. Instructions had been sent to those that did not have their own usernames. Any who have difficulty accessing the web site or Facilities for Notification list can contact Paul Roman for assistance.

13. Most Recent Status of Directory Phase II Process and NPCC Glossary of Terms

a. Status of Phase II of the Directory Development and the Revision Manual

Directories #9 and #10 are the first NPCC Directories reformatted into Phase II format and approved by the Full Members.

Phase II drafts of all Directories have been developed and further review of each is pending Task Force resources.

Directories under active Phase II development and review include Directory #1, Directory #6 and Directory #7.

14. Status of NERC Activities

a. NERC Operating Committee and Planning Committee Meetings

Jim Castle reported on the Operating Committee meeting highlights:

- Gerry Cauley stressed that the current focus of NERC is the identification of risk, prioritization of risk, learning from events and accountability to the public and the regulatory bodies. He reported that a summit of CEOs was being considered on Standards and CIP version 5.
- Sandia National Laboratories is reviewing a proposal for an Integrated Reliability Index (IRI) and will provide recommendations by September 2012. A statistical approach is being used to identify significant risk components and weighting factors. It is intended to have a phased development of the IRI concept which would develop an individual Event Driven Index (EDI), Condition Driven Index (CDI) and a Standards Driven Index (SDI).
- The Event Analysis Working Group Process Document was approved after revisions suggested by the Operating Committee were included.
- The OC will no longer support the manual time error correction elimination field trial. New Brunswick System Operator will take over from the IESO the Time Error Correction monitor role for the Eastern Interconnection starting on February 1, 2012.

- The Control Performance Standard 2 (CPS2) will be retired and replaced with the newly proposed BAAL limitation (ACE limits do not exceed the defined BAAL limit for more than thirty consecutive minutes). The BAAL field trial will continue until BAL-001-1 is approved.

Action Item: The NERC Operating Committee strategic plan will be included in the March 27-28 TFCO meeting material.

15. Proposal for EMS System Modeling Group

John Norden suggested that there is a need for better maintenance of the system models used in the NPCC member EMS systems. To improve the models it requires more and better coordination among NPCC RCs, TOPs and TOs regarding the EMS models. NERC standards also have specific requirements on this, for example see IRO-010-1a requirements below:

R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: (*Violation Risk Factor: Low*) (*Time Horizon: Operations Planning*)

R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments.

R1.2. Mutually agreeable format.

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 Planning Analyses).

R1.4. Process for data provision when automated Real-Time system operating data is unavailable.

R2. The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator. (*Violation Risk Factor: Low*) (*Time Horizon: Operations Planning*)

TFCO members agreed with the suggestions.

Action Item: John Norden will check if there are other specific NERC requirements that pertain to EMS system network modeling.

Action Item: Dave Daley/NPCC staff will request the CO-10 Working Group to address at their next meeting whether they have proper staffing to: 1) evaluate the existing EMS system models and 2) develop a process to coordinate the system models among the NPCC RCs, TOPs and TOs. The coordination should include the exchange of modeling information.

Prepared by Paul A. Roman
Draft for Comment Minutes issued February 17, 2012.
Draft for Approval Minutes issued March 22, 2012.
Final Minutes issued March 30, 2012.

Exhibit 1
2012 Meetings RCC / TFCO / TFCO Working Groups

Date	Meeting	Location
<u>FEBRUARY</u>		
February 1-2, 2012	CO-08	New York, New York-NPCC Offices
February 8-9, 2012	NERC ORS	
February 16-17, 2012	CO-01	New York, New York-NPCC Offices
<u>MARCH</u>		
March 1, 2012	RCC	New York, New York-Offices of Consolidated Edison Company
March 6-7, 2012	NERC OC	
March 8-9, 2012	CO-02	Boston, Massachusetts
March 13-14, 2012	CO-11	Montréal, Québec
March 27-28, 2012	TFCO (March 27 th : 1 PM-5 PM; March 28 th : 8 AM-5 PM)	New York, New York-NPCC Offices
March 29-30, 2012	CO-10	New York, New York-NPCC Offices
<u>APRIL</u>		
April 3-4, 2012	CO-12	New York, New York-NPCC Offices
<u>MAY</u>		
May 2-3, 2012	Spring Operators Seminar	Boston, Massachusetts
May 2-3, 2012	CO-08	Boston, Massachusetts
May 3, 2012	NPCC Media Teleconference	NPCC Board Room
May 8-9, 2012	NERC ORS	
May 16-17, 2012	TFCO (May 16 th : 8 AM-5 PM; May 17 th : 8 AM-1 PM)	Syracuse, New York
May 23-25, 2012	CO-01	Halifax, Nova Scotia

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TFCO Meeting of January 17-18, 2012

<u>JUNE</u>		
June 14-15, 2012	CO-11	Halifax, Nova Scotia
June 13, 2012	RCC	New York, New York-Offices of Consolidated Edison Company
June 19-20, 2012	NERC OC	
June 28-29, 2012	CO-10	Portland, Maine
<u>JULY</u>		
<u>AUGUST</u>		
August 16-17, 2012	CO-01	Montréal, Québec
August 23-24, 2012	CO-10	Montréal, Québec
August 30-31, 2012	TFCO (August 30 th : 8 AM-5 PM; August 31 st : 8 AM-1 PM)	Halifax, Nova Scotia
<u>SEPTEMBER</u>		
September 5-6, 2012	CO-08	Montréal, Québec
September 11-12, 2012	NERC ORS	
September 12, 2012	RCC	New York, New York-Offices of Consolidated Edison Company
September 18-19, 2012	NERC OC	
September 19-21, 2012	CO-02	Montréal, Québec
September 27-28, 2012	CO-11	New York, New York-NPCC Offices
<u>OCTOBER</u>		
October 17-18, 2012	TFCO (October 17 th : 8 AM-5 PM; October 18 th : 8 AM-1 PM)	Toronto, Ontario
<u>NOVEMBER</u>		
Late October to early November	CO-12	NPCC Office

November 7-8, 2012	Fall Operators Seminar (Québec)	Montréal, Québec
November 8-9, 2012	CO-10	Boston, Massachusetts
November 13-14, 2012	NERC ORS	
November 14-15, 2012	CO-08	Toronto, Ontario
November 27-28, 2012	RCC and General Meeting	Montréal, Québec
November 29-30, 2012	TFCO (November 29 th : 8 AM-5 PM; November 30 th : 8 AM-1 PM)	Montréal, Québec
<u>DECEMBER</u>		
December 6-7, 2012	CO-11	Toronto, Ontario
December 11-12, 2012	NERC OC	
December 12-14, 2012	CO-01	Toronto, Ontario

3/27/2012

From: [Jennifer L. Matz](#)
To: [Lee R. Pedowicz](#)
Subject: [rsvp-users] FW: Version 5 of the MRO Standards Process Manual will be open for 10-day ballot period
Date: Wednesday, April 04, 2012 6:43:34 PM
Attachments: [SPM Announcement of 10-day ballot period_03302012.pdf](#)

RSVP Users,

On Friday, March 30, 2012, MRO notified stakeholders about a 10-day ballot period opening up for Version 5 of the MRO Standards Process Manual. The 10-day ballot period will begin on April 13, 2012 and end on April 23, 2012. The ballot will take place through the [RSVP application](#). For those who did not receive the initial notice, the email (below) and notice are attached for your review.

To ensure your company's participation in the ballot period, MRO highly recommends reviewing your company's registrants in RSVP to ensure they are up to date. Please remember that only one person per company per segment can vote.

To view your company's registrants please select "By Company" in the left hand column on the RSVP application home web page.



Please feel free to contact me with questions.

Thank you,

Jennifer Matz

Compliance, Mitigation & Standards Administrator

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From: Jennifer L. Matz
Sent: Friday, March 30, 2012 4:39 PM
To: mro-all@midwestreliability.org
Cc: mrosc-mem@midwestreliability.org
Subject: Version 5 of the MRO Standards Process Manual will be open for 10-day ballot period

Greetings,

The following attachment is sent on behalf of Will Smith, MRO Manager of Standards and Program Performance.

Thank you,

Jennifer Matz

Compliance, Mitigation & Standards Administrator

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Date: March 30, 2012

To: Midwest Reliability Organization (MRO) Stakeholders

From: Will Smith, Manager of Standards and Program Performance

Cc: MRO Standards Committee

Subject: Version 5 of the MRO Standards Process Manual will be open for a 10-day ballot period

Dear MRO Stakeholders,

On February 23, 2012, the MRO Standards Committee approved to move version 5 of the MRO Standards Process Manual to ballot. Therefore, version 5 of the MRO Standards Process Manual will be open for a 10-day ballot period beginning on April 13, 2012 and ending on April 23, 2012. Please refer to the [RSVP application](#) to cast your vote. The ballot period is open to anyone; however, please make sure to register on the RSVP application ahead of time.

Please contact me with any questions at 651-855-1718 or ws.smith@midwestreliability.org.

Sincerely,

Will Smith
Manager of Standards and Program Performance





Midwest Reliability Organization

Regional Reliability Standards Process Manual

MRO Regional Reliability Standards Process Manual

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I. Introduction

Purpose:

This manual defines the characteristics of a Midwest Reliability Organization ("MRO") Regional Reliability Standard and establishes the process for proposing Regional Reliability Standards to North American Electric Reliability Corporation ("NERC") for enforcement under direct or delegated ~~regulatory~~ authority ~~consistent with~~ as designated by the Energy Policy Act of 2005 ("EPAct 2005"), Section 215 in the United States and applicable Canadian authorities. ~~The~~ MRO plans to become a Cross-Border Regional Entity ("CBRE") as defined in EPAct 2005 and the final FERC reliability rule consistent with the US-Canadian Bilateral principles. For more information on ~~the~~ MRO, please refer to <http://www.midwestreliability.org>.

The MRO standards process is consensus-based, technically vetted, and open to the public and bordering entities that may be impacted by a proposed Regional Reliability Standard ~~by the of~~ MRO. MRO Regional Reliability Standards apply to the reliability planning, and operation of bulk power systems located within the MRO region. NERC as the Electric Reliability Organization ("ERO"), and the applicable regulatory authorities in the ~~United~~ United States and Canada will have the ability to enforce these standards. ~~The MRO region is defined in agreements (e.g. delegation agreement) with NERC and applicable regulatory authorities in the United States and Canada.~~

~~Applicable Regulatory Authorities in the United States and Canada: FERC is the Applicable Regulatory Authority in the United States. The Manitoba Public Utilities Board is the Applicable Regulatory Authority in Manitoba. The Provincial Government of Saskatchewan is the Applicable Regulatory Authority in Saskatchewan.~~

Authority:

This manual is published by the authority of the MRO Board of Directors ("BOD") who shall have the sole authority to ~~modify~~ approve the modifications to this manual. A procedure for revising this manual is provided in ~~the~~ section VII titled "Maintenance of MRO Regional Reliability Standards ~~and~~ Process."

Credits:

This manual was developed from the NERC Reliability Standards Development Procedure (available at www.nerc.com). Thus, the MRO Regional Reliability Standards process is very similar to the NERC process and the format is the same as the NERC Reliability Standard format.

Background:

NERC and ~~the~~ MRO work with all segments of the electric industry, including electricity end-users, to develop standards for the reliable planning and operation of bulk ~~electric~~ power systems. The purpose of the NERC Reliability Standards is to promote reliability, while at the same time accommodating competitive electricity markets.

EPAct 2005, Section 215 and NERC, ERO provide for Regional Entities ("RE") to propose Regional Reliability Standards to NERC for eventual enforcement within the region of the RE or CBRE. Regions (such as ~~the~~ MRO) may develop, through their own processes, regional reliability standards that; go beyond, add detail to, or cover matters not addressed in NERC Reliability Standards. MRO Regional Reliability

Standards are proposed to NERC for approval and become enforceable, once approved by NERC and the applicable regulatory authorities in the United States and Canada as Reliability Standards.

MRO Regional Reliability Standards that are proposed shall not be inconsistent with, or less stringent than established NERC Reliability Standards. All MRO Regional Reliability Standards obligate ~~the~~ MRO to monitor and enforce compliance, apply sanctions, if any, consistent with any regional agreements and the NERC rules.

Proposed MRO Regional Reliability Standards shall be subject to approval by NERC, as the ERO, and by applicable regulatory authorities in the United States and Canada, before becoming mandatory and enforceable. No Regional Reliability Standard shall be effective within the MRO area unless approved by NERC and the applicable regulatory ~~authorities~~authority in the United States ~~and/or~~ Canada.

MRO proposed Regional Reliability Standards, when approved by NERC and the applicable regulatory authorities in the United States ~~and/or~~ Canada, shall be made part of the body of NERC Reliability Standards and shall be enforced upon ~~all~~ applicable bulk power system owners, operators, and users within the MRO region as ~~defined in agreements (e.g. per applicable~~ delegation agreements).~~).~~

II. MRO Regional Reliability Standard Definition, Characteristics, and Elements

Definition of a MRO Regional Reliability Standard:

A MRO Regional Reliability Standard defines certain obligations or requirements of entities that operate, plan, and use the bulk ~~electric~~power systems of the MRO region.

The Bylaws of ~~the~~ MRO define a Reliability Standard as: “

“Reliability Standard” means a NERC ~~requirement~~reliability standard, duly in effect, under the rules, regulations and laws governing such standards, to provide for reliable operation of the Bulk-Power System. The term includes requirements for the operation of existing Bulk-Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the Bulk-Power System. The term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.”

When proposing a Regional Reliability Standard in the MRO region, the obligations or requirements must be material to reliability and be measurable.

Each MRO Regional Reliability Standard shall enable or support one or more of the NERC reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk power system. Each of those standards shall also be consistent with all of the NERC reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

While MRO Regional Reliability Standards are intended to promote reliability, they must at the same time accommodate electricity markets. ~~Reliability is a necessity for electricity markets, and robust electricity markets can support reliability. Recognizing that bulk power system reliability and electricity markets are inseparable and mutually interdependent, all~~All MRO Regional Reliability Standards shall be consistent with NERC's market interface principles. Consideration of the market interface principles is intended to ensure that standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on electricity markets.

Characteristics of a MRO Regional Reliability Standard:

A MRO Regional Reliability Standard may include standards for the operation and planning of interconnected systems as well as market interface practices. The format and process defined by this manual applies to all MRO Regional Reliability Standards.

A MRO Regional Reliability Standard shall have the following characteristics:

- **Material to Reliability** - A MRO Regional Reliability Standard shall be material to the reliability of bulk ~~electric~~power systems in the MRO region. If the reliability of the bulk ~~electric~~power systems ~~could be~~is compromised without a particular standard or by a failure to comply with that standard, then the standard is material to reliability.
- **Measurable** - A MRO Regional Reliability Standard shall establish technical or performance requirements that can be practically measured.
- **Relative to NERC Reliability Standards** - A MRO Regional Reliability Standard shall go beyond, add detail to, or cover matters not addressed in already approved NERC Reliability Standards.

Elements of a MRO Regional Reliability Standard:

To ensure uniformity of MRO Regional Reliability Standards, a MRO Regional Reliability Standard shall consist of the elements identified in Appendix C of this manual. However, the most current version of the approved NERC Reliability Standard template and its associated elements posted on the NERC website will be used at the time of the development of a MRO Regional Reliability Standard if different from the elements listed in Appendix C.

These elements are intended to apply a systematic discipline in the development and revision of MRO Regional Reliability Standards. This discipline is necessary to achieving standards that are measurable, enforceable, and consistent.

The format allows a clear statement of the purpose, requirements, measures, and penalties for non-compliance associated with each standard.

All mandatory requirements of a MRO Regional Reliability Standard shall be within an element of the standard.

Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself. Types of supporting documents are described in a later section of this manual.

III. Roles in the MRO Regional Reliability Standards Development Process

Nomination, Revision or Withdrawal of a Standard:

Any member of ~~the~~ MRO or group within the MRO region shall be allowed to request that a MRO Regional Reliability Standard be developed, modified, or withdrawn. Additionally, any person (organization, company, government agency, individual, etc.) who is directly and materially affected by the reliability of ~~the~~ MRO bulk power system shall be allowed to request that a MRO Regional Reliability Standard be developed, modified, or withdrawn.

Process Roles

Board of Directors (BOD) - The BOD shall consider MRO Regional Reliability Standards that have been approved by the Registered Ballot Body ("RBB") and recommended by the Standards Committee to be proposed to NERC and the regulatory authorities for enforcement consistent with direct or delegated regulatory authorities of ~~the~~ MRO. Once the proposed MRO Regional Reliability Standard is approved by NERC and the regulatory authorities, it becomes effective in the MRO region consistent with the MRO's direct or delegated regulatory authority.

Compliance Committee (CC) - The mission of the MRO CC is to assure that the compliance program and policies are followed according to the rules and carried out in a non-discriminatory manner, subject to the BOD approval with MRO staff and BOD oversight. The compliance program is designed around compliance with Reliability Standards. The development of a MRO Regional Reliability Standard, in particular the measures and compliance administration portions of the standard, shall have direct input from the CC. ~~Field-testing~~

Standards Committee (SC) - The responsibilities of the SC will be managed include:

Managing the standards processes for development of standards, VRFs, VSLs, definitions, variances and ~~coordinated~~ interpretations in accordance with the CC, this manual. The responsibilities of the Standards Committee are defined in detail in the Standards Committee's Charter. The Standards Committee is responsible for ensuring that the standards, VRFs, VSLs, definitions, variances and interpretations developed by drafting teams are developed in accordance with the processes in this manual and meet NERC's benchmarks for reliability standards as well as criteria for governmental approval¹.

The Standards Committee has the right to remand work to a drafting team, to reject the work of a drafting team, or to accept the work of a drafting team. The Standards Committee may direct a drafting team to revise its work to follow the processes in this manual or to meet the criteria for NERC's benchmarks for reliability standards, or to meet the criteria for governmental approval. The Standards Committee shall meet at regularly scheduled intervals (either in person, or by other means). All Standards Committee meetings are open to all interested parties.

¹ The Ten Benchmarks of an Excellent Reliability Standard and FERC's Criteria for Approving Reliability Standards are posted on the NERC Standards Web Page.

When presented with a Standard Authorization Request (SAR) the Standards Committee shall determine if the SAR is sufficiently stated to guide standard development and whether the SAR is consistent with this manual. The Standards Committee shall take one of the following actions:

- Accept the SAR.
- Remand the SAR back to the standards staff for additional work.
- Reject the SAR. If the Standards Committee rejects a SAR, it shall provide a written explanation for rejection to the sponsor within fifteen business days of the rejection decision.
- Delay action on the SAR pending development of a technical justification for the proposed project

If the Standards Committee remands, rejects, or delays action on a SAR, the sponsor may file an appeal following the appeals process provided in this manual.

If the Standards Committee is presented with a SAR that proposes developing a new standard but does not have a technical justification upon which the standard can be developed, the committee shall direct the standards staff to post the SAR for a 30-day comment period solely to collect stakeholder feedback on the scope of technical foundation, if any, needed to support the proposed project. If a technical foundation is determined to be necessary, the Standards Committee shall solicit assistance from MRO's technical committees or other industry experts in providing that foundation before authorizing development of the associated standard.

If the Standards Committee accepts a SAR, the Standards Committee shall work with the standards staff to coordinate the posting of the SAR(s).

Compliance Manager (CM) – The Compliance Manager (CM), a MRO staff function, and the CC shall provide input and comments during the standards development process to ensure the measures will be effective and other aspects of the compliance program practically implemented.

~~**Standards Committee (SC)** – The responsibilities of the SC will include: management of the standards work flow so as not to overwhelm available resources; review of standards authorization requests and draft standards for such factors as completeness, sufficient detail, rational result, and compatibility with existing standards; clarifying standard development issues not specified in this procedure; and advising the BOD on standard development matters. Under no circumstance will the SC change the substance of a draft standard. The SC shall advise the BOD on MRO Regional Reliability Standards presented for their consideration in determining whether to propose such Reliability Standard to NERC.~~

Standards Process Manager (SPM) – This is a MRO staff function. The Standards Manager who will act as the SPM shall ~~administer~~manage the MRO Regional Reliability Standards Process. The SPM is responsible for ensuring that the development and revision of standards is in accordance with this manual. The SPM works to ensure the integrity of the process and consistency of quality and completeness of the MRO Regional Reliability Standards. The SPM facilitates all steps in the process.

Standards Process Staff - MRO staff will assist the SC, SPM, Requester, and Standard Drafting Team (SDT).

Registered Ballot Body (RBB) - The RBB comprises all entities that:

1. ~~qualify~~Qualify for one of the Industry Segments approved by the BOD², and
2. ~~are~~Are registered in the MRO RBB, ~~and~~
3. ~~are current with any MRO related designated fees associated with this program. Designated fees are defined as fees associated with the Standards Development process. At this time there are no fees for registration.~~

Each voter must be a member of the RBB. **Note: An individual's membership in the RBB will be in a "Pending" stage immediately following registration; in order to be able to vote, your registration must be activated, and activation may take up to 24 hours.**

Each registered member of the RBB is eligible to participate in the voting process for each Standards Action (add, change or withdraw). However, each MRO RBB member (company) may have only one vote per eligible segment.

The RBB will ensure, through its vote, the need for and the technical merits of, a proposed Standards Action and the appropriate consideration of views and objections received during the development process. The RBB votes to approve each Standards Action.

The MRO Regional Reliability Standards Process relies on open and inclusive participation by the electric utility industry and the interested public. Participation and voting is open to non-members of ~~the~~ MRO; at this time there are no fees for participation or voting.

Requester - A Requester is any person or entity (organization, company, government agency, etc.) that submits a complete request for development, revision, or withdrawal of a standard. Any person or entity that is directly and materially affected by an existing standard or the need for a new standard may submit a completed ~~Standard Authorization Request (SAR)~~SAR for any of the three following actions; a new standard to be developed, a revision to an existing standard, or a withdrawal of an existing standard.

SAR Drafting Team - A team of ~~technical~~industry experts ~~assigned~~appointed by the SC, that:

- ~~assists~~Assists in refining the SAR,
- ~~considers~~Considers and responds to comments, and
- ~~participates~~Participates in industry forums to help build consensus on the SAR.

Standard Drafting Team (SDT) - A ~~small~~ team (~~5-10 people~~) of ~~technical~~industry experts, ~~approved~~appointed by the SC, that:

- ~~develops~~Develops the details of the standard
- ~~considers~~Considers and responds to comments

² Appendix D contains a description of the latest version of the Industry Segments approved by the Board of Directors.

- ~~participates~~**Participates** in industry or regional forums to help build consensus on posted draft standards

Sub-Regional Variance: ~~An aspect of a Reliability Standard (one that is proposed for the MRO region for enforceability) that applies only within a particular A sub-regional entity sub-region. A Sub-Regional Variance may be used to exempt a group of entities within the MRO region from all or a portion of a Reliability Standard or may establish different measures or performance criteria as necessary to achieve variance is an approved, alternative method of achieving the reliability within the particular group of entities within the region. A Sub-Regional Variance may not be inconsistent with the Reliability Standard as it would otherwise exist without the variance. A Sub-regional intent of one or more requirements in a standard. No Regional Entity or bulk power system owner, operator, or user shall claim a sub-regional variance cannot establish from a level of regional reliability less than that set by a continent-wide Reliability Standard and standard without approval of such a sub-regional variance would only exempt a group of entities through the relevant standard approval procedure for the sub-regional variance. Each sub-regional variance from a MRO Reliability Standard-regional reliability standard that is approved by NERC and applicable governmental authorities shall be made an enforceable part of the associated regional reliability standard. Regional drafting teams shall aim to develop standards with requirements that apply on a regional basis, minimizing the need for sub-regional variances while still achieving the standard's reliability objectives. If one or more requirements cannot be met or complied with as written because of a physical difference in the bulk power system or because of an operational difference (such as a conflict with a Federally or Provincially approved tariff), but the requirement's reliability objective can be achieved in a different fashion, an entity or a group of entities may pursue a sub-regional variance from one or more requirements in a regional standard. It is the responsibility of the entity that needs a sub-regional variance to identify that need and initiate the processing of that sub-regional variance through the submittal of a SAR. Such a sub-regional variance may be proposed by a group of sub-regional entities and, if in accordance with Step 1 of this process manual. If approved by MRO, NERC and regulatory authorities, the sub-regional variance shall be enforced within the MRO region pursuant to its delegated authority.~~

IV. MRO Regional Reliability Standards Consensus Development Process

Overview

The process for development of MRO Regional Reliability Standards to be proposed to NERC and regulatory authorities for approval and eventual enforcement under direct or delegated authority is illustrated in the Process Diagram in Appendix A and has the following characteristics:

- **Inclusive** – Any entity (person, organization, company, government agency, individual, etc.) with a direct material interest in the bulk power system in the MRO area shall have a right to participate by: a) expressing a position and its basis, b) having that position considered, and c) having the right to appeal.

- **Openness** - Participation is open to all persons who are directly and materially affected by the reliability of the MRO region bulk power system. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in ~~the~~ MRO or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.
- **Balance** - The MRO Regional Reliability Standards Development Process shall have a balance of interests and shall not be dominated by any two, interest categories and no single interest category shall be able to defeat a matter.
- **Transparent** - All actions material to the development of MRO regional reliability standards shall be transparent. All standards development meetings shall be open and publicly ~~noticed~~announced on the MRO Web site.
- **Timeliness** - The MRO Regional Reliability Standards Development Process does not unnecessarily delay development of the proposed reliability standard.
- **Fair Due Process** - The MRO Regional Reliability Standards Development Process provides for reasonable notice and opportunity for public comment. The procedure includes public notice of the intent to develop a standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of all persons who are directly and materially affected.

The MRO Regional Reliability Standards development process is intended to develop consensus, first on the need for the standard, then on the standard itself. The process includes the following key elements:

- **Nomination of a proposed standard, revision to a standard, or withdrawal of a standard** using a ~~Standard—Authorization—Request~~ (“SAR”)-SAR.
- **Public posting of the SAR** to allow all parties to review and provide comments on the need for the proposed standard and the expected outcomes and impacts from implementing the proposed standard. Notice of standards shall provide an opportunity for participation by all directly and materially affected persons.
- **Review of the public comments** in response to the SAR and prioritization of proposed standards, leading to the authorization to develop standards for which there is a consensus-based need.
- **Assignment of teams** to draft the new or revised standard.
- **Drafting of the standard.**
- **Public posting of the draft standard** to allow all parties to review and provide comments on the draft standard. At this point the need for the standard has been established and comments should focus on aspects of the draft standard itself.

- **Field testing of the draft standard and measures:** The need and extent of recommendations for field testing shall be determined by the SDT and submitted through the SPM to the SC for approval. The SDT shall request input from the ~~RAC and CCMRO~~ Standing Committee members.
 - o Field-testing may be region-wide or may consist of one or more, lesser scale demonstrations, evaluations, or other SC approved methods.
 - o Field-testing should be cost effective and practical, yet sufficient to validate the requirements, measures, measurement processes and other elements of the standard necessary to implement the Compliance Program.
 - o For some standards and their associated measures, field-testing may not be appropriate, such as those measures that consist of administrative reports.
- **Formal balloting of the standard** for approval by the RBB.
- **Re-ballot to consider specific comments** by those submitting comments with negative votes.
- **Approval of a MRO Regional Reliability Standard.**
- **Appeals mechanism** as appropriate for the impartial handling of substantive and procedural complaints regarding action or inaction related to the standards process.

Process Steps

The first three steps in the MRO Regional Reliability Standards Development Process serve to establish consensus on the need for the standard.

Step 1 - Request to Develop a Standard ~~or~~, Revise ~~an~~ Existing Standard or withdraw a Standard

Objective: A valid SAR ~~that shall contain a description of the proposed regional reliability subject matter containing sufficient descriptive detail to~~ clearly ~~justifies~~ define the purpose ~~for~~, scope, impacted parties, and ~~describes the scope of other relevant information of~~ the proposed ~~standards action~~ standard. An example of a SAR form can be found in Appendix B.

Sequence Considerations: Submitting a valid SAR is the first step in proposing a standard action. A requester may prepare a draft of the proposed standard ~~(Step 5)~~, which the SC may authorize for concurrent posting with the SAR. This could be useful for a standard action with a clearly defined and limited scope or one for which stakeholder consensus on the need and scope is likely. Complex standards where broad debate of issues is required should be, presented in two stages. The first stage is ~~is~~, the completion of a valid SAR to get agreement on the scope and purpose, the second stage is the development of the standard later in Step 6.

Requests to develop, revise, interpret, or withdraw³ a MRO Regional Reliability Standard shall be submitted to the SPM by completing a SAR. Actions in the remaining steps of the standards process apply to proposed new standards, revisions to existing standards, sub-regional variances, interpretations, or withdrawal of existing standards, unless explicitly stated otherwise.

The SAR is a description of the subject matter of the new or revised standard along with a proposed implementation plan and includes:

- Descriptive detail to clearly define the scope of the standard.
- A statement of the purpose of the standard
- A needs statement that provides justification for the development or revision of the standard; including an assessment of the reliability and market interface impacts of implementing or not implementing the standard.

Appendix B provides a sample template of the SAR form.

The SPM shall maintain the SAR form and make it available electronically.

Any person or entity directly or materially affected by an existing standard or the need for a new or revised standard may initiate a SAR.

The Requester shall submit the SAR to the SPM electronically through the RSVP Reliability Standards Voting Process (RSVP) application and the SPM shall electronically acknowledge receipt of the SAR within 15 days. The SPM shall send the electronic acknowledgement simultaneously to the Requester and to NERC.

The SPM shall assist the Requester in developing the SAR, reviewing NERC Reliability Standards to see whether they already address the need, identify issues with interconnected regions, and verify that the SAR complies with this manual. The SPM will respond to the requester within 45 days of the request.

The SPM shall forward all properly completed SARs to the SC. The SC shall meet at established intervals to review all pending SARs. The frequency of the review process will depend on workload; in no case shall a properly completed SAR wait for SC action more than 60 days from the date of receipt.

Within [no greater than 60] days of receipt of a completed standard request, the [standards] committee shall determine the disposition of the standard request. The SC may take one of the following actions:

- ~~• Remand the SAR back to the SPM for additional work and information from the Requester.~~
- ~~• Accept the SAR as a candidate for a new or revised standard. If the SC accepts a SAR as a candidate for a new or revised standard, it will provide technical support and analysis of comments for that SAR, and assist the Requester and the SPM in the remaining steps of the process.~~

~~3 Actions in the remaining steps of the standards process apply to proposed new standards, revisions to existing standards, or withdrawal of existing standards, unless explicitly stated otherwise.~~

- Accept the standard request as a candidate for development of a new standard, revision of an existing standard, or deletion of an existing standard. The SC may, at its discretion, expand or narrow the scope of the standard request under consideration. The SC shall prioritize the development of the standard in relation to other proposed standards, as may be required based on the volume of requests and resources.
- Reject the SAR—standard request. If the SC rejects a SAR, it will provide standard request, a written explanation for rejection will be delivered to the Requesterrequester within [no greater than 30] days of the rejection decision. If the SC rejects a SAR, the Requester may file an appeal following the Appeals Process
- Remand the standard request back to the requester for additional work. The SPM will make reasonable efforts to assist the requester in addressing the deficiencies identified by the SC. The requester may then resubmit the modified standard request using the process above. The requester may choose to withdraw the standard request from further consideration prior to acceptance by the SC.

The status of SAR shall be tracked electronically by the SPM. The SAR and its status shall be posted for public viewing including any actions or decisions.

Step 2 - Solicit Public Comments on the SAR

Objective: Establish that there is stakeholder consensus on the need, scope and applicability of the requester's proposed standards' action.

Sequence Considerations: A SAR may be posted only after completion of Step 1. A SAR may at the discretion of the SC, be posted for comment concurrently with a draft standard (Step 6).

Once a SAR has been accepted by the SC as a candidate for the development of a new or revised standard, the SPM shall post the SAR on the RSVP Application for the purpose of soliciting public comments.

The SPM shall notify the RBB, the MRO region, NERC, and other interested parties that the SAR has been accepted by the SC and posted for comment.

Within thirty (30) days of acceptance by the SC, the SAR shall be posted electronically and comments on the SAR(s) will be accepted for a ~~21~~30-day period from the date of posting. Comments will be accepted on-line using the RSVP application. The SPM will provide a copy of the comments to the Requester. In addition, comments will be visible to the RBB during the commenting period. Based on the comments, the Requester may decide to: submit the SAR for authorization, withdraw the SAR, or revise and resubmit it to the SPM for another posting in the next available comment period.

The Requester shall give prompt consideration to the written views and objections of all participants. The Requester, with support from the SPM or SPM assigned staff, shall make an effort to resolve all expressed objections and shall advise each objector of the disposition of the objection and the reasons therefore. In addition,

the SPM shall inform each objector that an appeals process exists within the MRO standards process.

While there is no established limit on the number of times a SAR may be posted for comment, the SC retains the right to reverse its prior decision and reject a SAR if it believes continued revisions are not productive. Once again, the SC shall notify the Requester in writing of the rejection and the availability of the Appeals Process. During the SAR comment process, the Requester may become aware of potential sub-Regional differences (within ~~the~~ MRO) related to the proposed standard. To the extent possible, the Requester should make any sub-Regional differences or exceptions a part of the SAR so that, if the SAR is authorized, such variations will be made a part of the draft new or revised standard.

Step 3 - Authorization to Proceed With Drafting of a New or Revised Standard

Objective: Authorize development of a standard that is consistent with the SAR and for which there is stakeholder consensus on the need, scope and applicability.

Sequence Considerations: The SC may formally authorize the development of a standards' action only after due consideration of SAR comments to determine there is consensus on the need, scope and applicability of the proposed standard. ~~This does not preclude, however, the requester from previously preparing a draft standard for consideration and the SC from authorizing a concurrent posting of the draft standard for comment along with the SAR.~~

After the public provides comments on the SAR, the Requester may decide to submit the SAR to the SC for authorization to draft the standard. The SC reviews the comments received in response to the SAR and any revisions to the SAR. The SC, considering the public comments received and their resolution, may then take one of the following actions:

- Authorize the drafting of the proposed standard or revisions to a standard.
- Reject the SAR with a written explanation to the Requester and post that explanation.

If the SC rejects a SAR, the Requester may file an appeal.

Step 4 – Formation of the SDT

Objective: Appoint a SDT that has the expertise, competencies, and diversity of views that are necessary to develop the standard.

Sequence Considerations: The SC may appoint a SDT concurrently with or after authorization of the development of a standard (Step 3).

For each new SAR, the SPM shall post a request that interested parties complete a "SDT Self-Nomination" form utilizing the RSVP application. Those individuals who complete and submit these self-nomination forms through the RSVP will be considered for appointment to the associated SDT.

Once a SAR has been authorized by the SC to proceed to the drafting stage, the SC shall assign the development of the standard to a SDT. The SPM shall recommend a list of candidates for appointment to the team and shall submit the list to the SC. ~~The SC may accept the recommendations of the SPM or may select other individuals to serve on the SDT within 60 days.~~The SC shall appoint the drafting team membership within 60 days of accepting a standard request for development, modifying the recommendations of the SPM as the committee deems appropriate, and assign development of the proposed standard to the drafting team. In the event that the SC is unable to appoint a drafting team within 60 days, one shall be appointed at the earliest possible date.

The SDT shall elect a Chairman for their team. This team shall consist of a small group of people who collectively have the necessary technical expertise and work process skills. ~~A representative of the CC or their designee, plus a Reliability Assessment Committee (RAC) representative or their designee should be included as a member of each SDT.~~

The SPM shall assign MRO Standards Process staff personnel to assist in the drafting of the standard.

Step 5 - Draft New or Revised Standard

Objective: Develop a standard within the scope of the SAR.

Sequence Considerations: Development of the draft standard follows the authorization by the SC (Step 3) and appointment of a SDT (Step 4). Steps 5 and 6 may be iterated as necessary to consider stakeholder comments and build consensus on the draft standard.

The drafting team shall develop a work plan for completing the regional reliability standard, including the establishment of a milestone schedule for completing critical elements of the work in sufficient detail to ensure that the drafting team will meet the objectives established by the SC. The drafting team shall submit its work plan to the SC for its ~~concurrence~~approval.

The drafting team shall convene periodically, either in person or by electronic means as necessary, to establish work teams (made up of members of the drafting team) as necessary, and perform other activities to complete the proposed standard within the milestone date(s) agreed upon by the SC.

The work product of the drafting team will consist of the following:

- A draft standard consistent with the standard request on which it was based.
- An assessment of the reliability impact of the standard request within the region and in neighboring regions, including appropriate input from the neighboring regions if the standard request is determined to impact any neighboring region.
- An implementation plan, including the nature, extent and duration of field-testing needed, if any.
- Identification of any existing standard that will be deleted, in part or whole, or otherwise impacted by the implementation of the draft standard.

- Technical reports, white papers and/or work papers that provide technical support for the draft standard under consideration.

The team regularly (at frequency determined by the SC) shall inform the SC of its progress in meeting a timely completion of the draft standard.

~~The drafting of measures and compliance administration aspects of the standard will be coordinated with the CC.~~

If the SDT determines that the scope of the SAR is inappropriate based on its own work and stakeholder comments, the team shall notify the SC. The SDT may recommend the scope of the standard be reduced to allow the effort to continue forward, while still remaining within the scope of the SAR. Reducing the scope defined in the SAR is acceptable if the SDT finds, for instance, that additional technical research is needed prior to developing a portion of the standard or issues need to be resolved before consensus can be achieved on a portion of the standard. In this case, the SDT shall provide detailed justification of need for reducing the scope. The SC, based on the SDT recommendation and a review of stakeholder comments, will determine if the change in scope is acceptable.

If the SDT determines it is necessary to expand the scope of the standard or to modify the scope in a way that is no longer consistent with the scope defined in the SAR, then the SDT may initiate or recommend another requester initiate a new SAR (Step 1) to develop the expanded or modified scope. At no time will a SDT develop a standard that is not within the scope of the SAR that was authorized for development.

If the SDT elects to narrow the SAR, scope or identifies issues not in the SAR scope, then a report shall be prepared and sent to the SC.

Once the standard has been drafted, the SPM in conjunction with the SC shall perform a review ~~the standard for consistency of quality⁴~~ and completeness. The review for quality may include a legal review in conjunction with the quality review. Issues discovered after the quality review will be brought to the attention of the SDT for resolution.

Each reliability standard shall 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 shall establish an objective that is the best approach for bulk power system reliability, considering the costs and benefits of implementing the proposal. Each requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement.

Requirements should have the following characteristics:

- Each requirement shall 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.

⁴ See the latest NERC Quality Review Document.

- 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 shall be designed to apply throughout the interconnected MRO Bulk-Power System.

The SPM shall also ensure the draft standard is within the scope and purpose identified in the SAR. This review shall occur within a 15-day period.

~~The~~At the direction of the SC, the SPM shall post the new or revised standard for public comment once this review is completed. The SPM shall notify the RBB, the MRO region, NERC, and other interested parties that the new or revised standard has been posted for public comment.

Step 6 - Solicit Public Comments on Draft Standard

Objective: Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to achieve consensus.

Sequence Considerations:

The posting of a draft standard will occur after the appointment of a SDT and development of a draft by the team. Alternatively, a draft standard submitted by the requester may be posted for comment concurrently with the associated SAR, with the condition that the SAR and draft standard meet the requirements of this procedure and are consistent with each other. In all cases, public comments on the draft standard shall be solicited prior to the SC approving the standard going to ballot (Step 9).

Once a draft standard has been verified by the SPM to be within the scope and purpose of the SAR and in compliance with this manual, the SPM will post the draft standard for the first formal comment period. The posting of the draft standard will be linked to the SAR for reference. Comments on the draft standard will be accepted for a minimum 30-day period from the notice of posting. Comments will be accepted on-line using the RSVP application and will be viewable during the posted commenting period.

~~Since the need for the standard was established by authorization of the SAR, comments at this stage should identify specific issues with the draft standard and propose alternative language. The comments may include recommendations to accept or reject the standards and reasons for that recommendation.~~

The SDT shall develop an implementation plan for the standard that will be posted in conjunction with the standard for at least one stakeholder comment period. Once the implementation plan has been developed and posted for stakeholder comment, it shall remain part of the standard action for subsequent postings and shall be included on the ballot for the standard. The implementation plan shall describe when the standard will become effective. If the implementation is to be phased, the plan will describe which elements of the standard are to be applied to each class of responsible entities, and when. The plan will describe any deployment considerations unique to the standard, such as computer applications, measurement devices, databases, or training, as well as any other special steps necessary to prepare for and initially implement the standard.

The second formal comment period will be 45-day duration and will take place after the SDT has posted its consideration of comments and conforming changes to the associated standard using the RSVP application. Formation of the ballot pool will take place during the first 30-days of the 45-day posting and balloting, in accordance with Step 9, will occur during the last 10-days.

In all cases, public comments on the draft standard shall be solicited prior to the SC approving the standard going to ballot (Step 9).

Step 7 - Field Testing (At the discretion of the SC)

Objective: Determine ~~what~~if testing is required to validate the concepts, requirements, measures and compliance elements of the standard and implement that testing.

Sequence Considerations: Testing may be completed during or after Steps 1 through 6. Testing and associated analysis of results (Step 8) must be completed prior to determining whether to submit the standard to ballot (Step 9).

Taking into consideration stakeholder comments received through Step 6, the SDT may recommend to the SC or the SC may mandate that a test of one or more aspects of a standard is needed. The MRO Compliance Manager will also evaluate whether field-testing of the compliance elements of the proposed new or revised standard is needed and advise the SC. The SC will approve all field tests of proposed standards based on the recommendations of the SDT and the ~~compliance manager~~Compliance Manager. If needed, the SC will also request inputs on technical matters from applicable standing committees or other experts.

Once the field-testing plan is approved, the SPM will, under the direction of the SC, oversee the field-testing of the standard. Throughout the field testing process, compliance with the existing standard is required.

In some cases, measurement may be an administrative task and no field-testing is required at all.

In other cases, one or more limited scale demonstrations, evaluations, or other SC approved method may be sufficient.

Step 8 - Analysis of the Comments and Field Test Results

Objective: Evaluate stakeholder comments and field test results to determine if there is consensus that the proposed standard should go to ballot or requires additional work.

Sequence Considerations: This step follows Steps 6 and 7 and must precede Step 9.

The SPM will assemble the comments on the draft standard and distribute those comments to the SDT ~~and the requester.~~ The SDT, ~~assisted by the requester,~~ shall give prompt consideration to the written views and objections of all participants. An effort to resolve all expressed objections shall be made, and each objector shall be

advised of the disposition of the objection and the reasons therefore. The ~~STDS~~SDT shall prepare a summary of the comments received and the changes made to the proposed standard as a result of these comments. The ~~STDS~~SDT shall summarize comments that were rejected by the ~~STDS~~SDT and the reason(s) that these comments were rejected, in part or whole. The summary, along with a response to each comment received will be posted on the MRO website no later than the next posting of the proposed standard. In addition, each objector will be informed that an appeals process exists within the MRO standards process.

Based on comments received, the SDT may determine there is an opportunity to achieve consensus for the standard. In this case, the SDT may elect to return to Step 5 and revise the draft for another posting. Although there is no predetermined limit on the number of times a draft standard may be revised and posted, the SDT should ensure the potential benefits of another posting outweigh the burden on the SDT and stakeholders. Returning to Step 5 to continue working on the standard is the prerogative of the SDT, subject to SC oversight.

If the SDT determines the draft standard is ready for ballot, the SDT shall submit the draft standard to the SC with a request to proceed to balloting, along with the comments received and responses to the comments. Based on the comments received and field-testing, the SDT may include revisions that are not substantive. Substantive changes to a draft standard shall not be permitted between the last posting for stakeholder comment and submittal for ballot. A substantive change is one that directly and materially affects the intent or use of the standard. For example, adding, deleting, or revising requirements; or adding, deleting, or revising measurements for which compliance is mandatory. Any non-substantive changes such as: spelling, grammar, or formatting, made prior to going to ballot, will be identified to stakeholders at the time of the ballot notice. If the SDT determines, based on comments received, that substantive changes to the standard are required, the standard will be re-posted for comment and a notice sent to the MRO region, the RBB, NERC, and other interested parties that the revised standard has been re-posted for public comment.

When the SC receives a draft standard that has been recommended for ballot, the SC will review the standard to ensure that the proposed standard is consistent with the scope of the SAR; addresses all of the objectives cited in Steps 1-8, as applicable; and is compatible with other existing standards. If the proposed standard does not pass this review, the SC shall remand the proposed standard to the SDT to address the deficiencies. If the proposed standard passes the review, the SC shall set the proposed standard for ballot as soon as the workflow will accommodate.

If the ~~SC or~~ SDT determines there is insufficient consensus to ballot the standard and ~~that~~ further work is unlikely to achieve consensus, the ~~following may occur: (1) the~~ SDT may recommend to the SC that ~~the~~ standard drafting be terminated and the SAR withdrawn. ~~The SC will consider the recommendation of the SDT and stakeholder comments and or (2) the SC~~ may terminate the standard drafting and accept the withdrawal of the SAR. ~~–~~ If the SC believes the ~~SDT~~ recommendation is unsubstantiated, the SC may direct other actions consistent with this procedure, such as requesting the SDT to continue or appointing a new SDT.

Step 9 - Ballot the New ~~or~~ Revised or Withdrawal of Standard

Objective: Approve the proposed standard by vote of industry stakeholders.

Sequence Considerations: The SC ~~shall~~may determine, upon recommendation from the SDT, that all requirements of Steps 1 through 8 have been satisfactorily met before authorizing an action to go to ballot.

If the ~~SDT~~SC decides to submit the standard to a vote, the SPM shall provide notice of such to the RBB, NERC, as well as other interested parties, and electronically post the standard, and all comments received, the responses to those comments, and an implementation plan. Once the notice for a vote has been issued, no substantive modifications may be made to the proposed standard unless the revisions are posted and a new notice of the vote is issued.

First Ballot

Each voter must be a member of the Registered Ballot Body (RBB). **Note: An individual's membership in the RBB will be in a "Pending" stage immediately following registration; in order to be able to vote, your registration must be activated, and activation may take up to 24 hours.**

The ballot will be conducted electronically through the RSVP application. In the event of balloting difficulties the SC will address and decide accordingly. All members of the RBB shall be eligible to vote on the associated standard except, that only one member from an entity may vote in any given segment. It is the responsibility of the entity to identify and notify the SPM of the eligible voter. The voting options are:

- Affirmative, with or without comment;
- Negative, with or without comment (the comments for a negative vote may be given and, if possible, should include specific wording or actions that would resolve the objection);
- Abstain.

The time window for voting shall be designated when the draft standard is posted. In no case shall the voting time window start sooner than fifteen (15) and no later than thirty (30) days from the notice of the posting. The voting time window will be a period of ten (10) days.

This provides a minimum total of twenty-five (25)-days from the initial notice until the end of the voting period. Approval of a MRO Regional Reliability Standard or revision to a MRO Regional Reliability Standard requires:

- ~~a~~A quorum, which is established by at least 4 of the Segments submitting a response with an affirmative vote, a negative vote, or an abstention; and
- ~~an~~An affirmative vote from at least two-thirds of the segments participating in the vote. Each segment vote is determined by the majority of the votes cast in the segment, either affirmative or negative. Abstentions and non-responses will not be counted.

Voting results, comments, and responses, if necessary, will be posted for public viewing as soon as practical after the balloting period closes. Voting results and comments may be posted prior to the responses.

Balloting examples are provided in Appendix D.

Members of the RBB should submit any comments on the proposed standard during the public comment period. If any Negative votes with comments are received during the ballot period, they shall be addressed in accordance with *Step 8* and included with the re-circulation ballot.

The SPM shall ~~facilitate~~assist the SDT, ~~assisted by the Requester,~~ in preparing a response to negative votes submitted with comments.

In addition, the SPM will inform each objector that an appeals process exists within the MRO standards process. A negative vote that does not contain comments does not require a response. If there are no negative votes with comments from the first ballot, then the results of the first ballot shall stand. If however, one or more members submit negative votes with comments, regardless of whether those comments are resolved, a second ballot shall be conducted.

If a quorum of the Segments is not established, the standard shall be re-balloted, allowing ten (10) days for the ballot. If a quorum is not established with the re-ballot, the SPM shall survey the RBB to establish interest in participating in a ballot on the standard.

Second Ballot

In the second ballot (also called a “re-circulation ballot”), members of the RBB shall again be presented the proposed standard (unchanged from the first ballot) along with the reasons for negative votes, the responses, and any resolution of the differences.

All members of the RBB eligible to vote shall be permitted to reconsider and change their vote from the first ballot. Eligible voting members of the RBB that did not respond to the first ballot shall be permitted to vote in the second ballot. Only one vote will be accepted from each organization within a segment.

In the second ballot, votes will be counted by exception only - members on the second ballot may indicate a revision to their original vote, otherwise their vote shall remain the same as in the first ballot. If a second ballot is conducted, the results of the second ballot shall determine the status of the standard, regardless of the outcome of the first ballot.

The voting time window for the second ballot is ten (10) days (to allow members to review comments and responses). The 21-day posting is not required for the second ballot. Members of the RBB may submit comments in the second ballot but no response to those comments is required.

In the second ballot step no revisions to the standard are permitted, as such revisions would not have been subject to public comment. However, if the SC determines that revisions proposed during the ballot process would likely provide an opportunity to achieve consensus on the standard, then such revisions may be made and the draft standard posted for public comment again beginning with Step 6 and continuing with subsequent steps.

The SPM shall post the final outcome of the ballot process. If the standard is rejected, the process is ended and any further work in this area would require a new

SAR. If the standard is approved, the SPM shall post the consensus standard and the SC Chair shall present it to the BOD for consideration.

Step 10 – Board of Director (BOD) Approval of a Proposed MRO Regional Reliability Standard

Objective: To have the BOD approve the proposed new or revised, MRO Regional Reliability Standard. Once properly approved by the BOD, accepted by NERC, and accepted for filing by the applicable regulatory authorities in the United States and Canada, the Reliability Standard becomes enforceable.

Sequence Considerations: The thirty (30)-day notice prior to action by the BOD may begin concurrently with or any time after the start of the first ballot. The thirty (30)-day period shall not end any sooner than the end of the final ballot.

A MRO Regional Reliability Standard submitted for consideration to the BOD must be publicly posted and noticed no less than fifteen (15) and no more than thirty (30) days prior to action by the BOD, included with the standard is the implementation plan that was part of the posting process.

At a regular or special meeting, the BOD shall consider the proposed MRO Regional Reliability Standard. The BOD shall consider the results of the balloting and dissenting opinions. The BOD shall consider any advice offered by the MRO SC. The BOD may accept or reject a standard, but may not substantively modify a proposed MRO Regional Reliability Standard. If the BOD chooses not to propose a standard to NERC and the applicable regulatory authorities in the United States and Canada, it shall provide its reasons for not doing so. Upon acceptance of the standard, the SPM will submit the standard to NERC for approval and filing with the applicable regulatory authorities in the United States and Canada.

A MRO Regional Reliability Standard that is approved by NERC and filed with the applicable regulatory authorities shall become effective in accordance with applicable NERC and applicable regulatory proceedings. The implementation plan is included with the proposed Reliability Standard.

The SPM shall publicly post the standard, showing the final status.

Step 11 - Implementation of the MRO Regional Reliability Standard

Objective: That Organizations subject to the standard use the standard, and the compliance program incorporates the standard into its compliance monitoring and enforcement process.

Sequence Considerations: The effective date of a standard is defined in the standard implementation plan.

After approval of a MRO Regional Reliability Standard by the applicable authorities in the United States and Canada, the SPM will forward the standard to the Compliance Manager for implementation, enforcement, and monitoring by the CC which will oversee the implementation and assess the effectiveness.

V. Interpretations and Appeals

Interpretations of MRO Regional Reliability Standards

All persons who are directly and materially affected by the reliability of MRO bulk power systems shall be permitted to request an interpretation of a MRO Regional Reliability Standard. The person requesting an interpretation shall ~~send~~submit a ~~request~~SAR form to the SPM explaining the specific circumstances surrounding the request and what clarifications are required as applied to those circumstances. The ~~request~~SAR should indicate the material impact to the requesting party or others caused by the lack of clarity or a possibly incorrect interpretation of the standard. The SPM shall provide notice to the MRO region within ten business days of such a request for interpretation.

~~The SPM shall recommend a list of candidates with the relevant expertise for appointment to an interpretation team and shall submit the list to the SC. Where practical, the SPM will assign the project to the team that developed the associated standard, or to a subset of that drafting team. Once assigned the project, the drafting team should draft and post its interpretation as quickly as practical. The interpretation is intended to provide greater clarity to an existing requirement, and should not modify the intent of the original requirement.~~

As soon as practical (not more than 45 days), the SDT will draft a written interpretation to the standard addressing the issues raised. The SPM shall take the draft interpretation to the SC for acceptance, ~~which would be forwarded to the Board for approval, at the SC recommendation. If approved by the Board, and coordination of a quality review. The quality review will assess whether the interpretation is appended to the standard and is effective immediately. The SPM will send notice to all entities that operate, plan, clear and use provides the bulk electric systems of requested clarity without expanding the MRO region requirement. The results of this review will be provided to the SDT and the SC. After consultation with the SDT, the SC will decide if the interpretation will stand until the standard is revised through the normal process, at which time the standard will be modified to incorporate the clarifications provided by the interpretation is ready for posting.~~

The first formal comment period shall be 30-days. The SDT will consider stakeholder input provided during the comment period. If substantive changes are required to the interpretation, another quality review may be required. The second formal comment period shall be 45-days. The initial ballot shall occur during the last 10 days of the 45 day comment period. Balloting shall be consistent with Step 9. Once the ballot is successful, the interpretation shall be sent to the MRO BOD for approval in accordance with Step 10. Implementation of the interpretation will be consistent with Step 11.

Withdrawal of an Interpretation

The interpretation shall stand until such time as the interpretation can be incorporated into a future revision of the regional standard or the interpretation is retired due to a future modification of the applicable requirement. If the interpretation needs to be retired, a SAR shall be prepared and submitted in

accordance with Steps 8, 9 and 10 contained in this MRO Regional Reliability Standards Process Manual.

Appeals

Persons who have directly and materially affected interests and who have been or will be adversely affected by any substantive or procedural action or inaction related to the development, approval, revision, or withdrawal of a MRO Regional Reliability Standard shall have the right to appeal. This appeals process applies only to the MRO Regional Reliability Standards process as defined in this manual.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. In all cases, the request for appeal must be made prior to the next step in the process.

The final decisions of any appeal shall be documented in writing and made public.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants:

Level 1 Appeal

Level 1 is the required first step in the appeals process. The appellant shall submit to the SPM, a complaint in writing that describes the substantive or procedural action or inaction associated with a MRO Regional Reliability Standard or the MRO Regional Reliability Standards process. The appellant shall describe in the complaint the actual or potential adverse impact to the appellant. Assisted by any necessary staff and ~~committee~~SC resources, the SPM shall prepare a written response addressed to the appellant as soon as practical but not more than 45 days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response shall be made a part of the public record associated with the standard.

Level 2 Appeal

If, after the Level 1 Appeal the appellant remains unsatisfied with the resolution, and indicates such in writing to the SPM, the SPM shall convene a Level 2 Appeals Panel. This panel shall consist of five (5), panel members total appointed by the BOD. In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The SPM shall post the complaint and other relevant materials and provide at least 30 days notice of the meeting of the Level 2 Appeals Panel. In addition to the appellant, any person that is directly and materially affected by the substantive or procedural action or inaction referenced in the complaint shall be heard by the panel. The panel shall not consider any expansion to the scope of the appeal that was not presented in the Level 1 Appeal. The panel may in its decision find for the appellant and remand the issue to the SC with a statement of the issues and facts in regard to which fair and equitable action was not taken. The panel may find against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections. The panel may not, however, revise, approve, or disapprove a MRO Regional Reliability Standard, as

these responsibilities remain with the standard's RBB and BOD respectively. The SPM shall publicly post the actions of the Level 2 Appeals Panel.

In addition to the foregoing, a procedural objection that has not been resolved may be submitted to the BOD for consideration at the time the BOD decides whether to approve proposing a particular MRO Regional Reliability Standard for NERC consideration and eventual enforceability. The objection must be in writing, signed by an officer of the objecting entity, and contain a concise statement of the relief requested and a clear demonstration of the facts that justify that relief. The objection must be filed no later than 30 days after the announcement of the vote by the RBB on the MRO Regional Reliability Standard in question.

VI. Errata

Approved Reliability Standards

From time to time, an error may be discovered in an approved regional reliability standard. If the Standards Committee agrees that the correction of the error does not change the scope or intent of the associated standard, and agrees that the correction has no material impact on the end users of the standard, then the correction shall be submitted for information to the MRO Board of Directors and filed for approval with applicable governmental authorities. The MRO Board of Directors has resolved to concurrently approve any errata approved by the Standards Committee.

Errata are errors in approved standards that, if corrected, do not change the scope or intent of the associated approved standard and do not have a material impact on the end users of the standard.

1. If the error falls into one of the following categories, the SPM will produce a red line version of the standard that shows the proposed correction:
 - a. A misspelled word
 - b. An incorrect reference to a requirement or measure
 - c. A missing word that, when added, improves readability but does not change the technical content
 - d. An error that, if corrected, does not change the scope or technical content of the standard
 - e. A discrepancy between the redline and clean versions of a balloted standard
2. If the error does not fall into the above categories as errata, the SPMSC will make not review the standard to determine if the criticality of the error for inclusion in warrants actions prior to the next SAR submitted to revise the associated scheduled review of the standard.
- ~~3. The Standards Committee will review the clean and red line versions of the standard, and if the proposed modification falls into the category of errata as defined above, then the SPM will post the clean and red line versions of the standard for a 30-day comment period. The comment form must ask stakeholders if they agree that the proposed modification is immaterial, and if stakeholders believe the modification(s) is material, stakeholders must identify the specific material impact of the proposed modification. Once posted, an announcement will be sent to the stakeholders along with a notice indicating when the BOD will act on the errata.~~
- ~~4. The drafting team will prepare a response to stakeholder comments and submit a recommendation to the entire Standards Committee.~~
- ~~5. The standards committee will determine whether to authorize moving the errata forward for BOD adoption and filing with regulatory authorities.~~
- ~~6. The SPM will submit the errata to the BOD for their approval and then send notice of the errata to applicable regulatory authorities.~~

- ~~7. The SPM will modify the BOD approved version and all regulatory approved versions of the standard to include the approved correction and send a notice of the approval and associated modification to the stakeholders.~~

Draft Standards

If a draft standard is found to have errata, as defined above, during an initial or recirculation ballot period; the SPM shall be allowed to make the changes. The SPM will post a redline version of the document and notify stakeholders.

Errata found during commenting periods will be handled by the commenting process as defined in steps 1 – 8 of section IV.

VII. Maintenance of MRO Regional Reliability Standards Process

Process Revisions

A request to substantively change the MRO Regional Reliability Standards Process Development process shall begin with the preparation of a SAR, and be handled using the same procedure as a request to revise a MRO Regional Reliability Standard. The exception is that a single ballot without regard to negative comments from the RBB shall be conducted and the results of that ballot will be binding. Non-substantive changes will be handled through the abbreviated process listed below. Once approved by the RBB, any proposed revisions to this manual would go to the BOD, NERC, and the applicable authorities in the United States and Canada for approval.

The BOD may make changes to the Industry Segments referenced in Appendix D. These changes shall be carried over to this process without the need to prepare a SAR. In addition, the SC may alter the document number on any existing or proposed standard without going through the MRO Regional Standards Process.

Abbreviated Process for Procedural/Administrative Changes

The SPM shall handle all procedural/administrative requests using an abbreviated process described here. The SPM shall post all proposed procedural/administrative revisions to the MRO Regional Reliability Standards Development Process for a minimum 30-day ~~public~~ comment period. The SC shall consider all comments received and modify the proposed revisions as needed. Based on the degree of consensus for the revisions, the SC may:

- a. ~~submit~~Submit the revised procedure directly to the BOD for adoption;
- b. ~~submit~~Submit the revised procedure for ballot pool approval prior to submitting it for BOD adoption (the regular voting process in the procedure, including a re-circulation ballot if needed, would be used and the results of the ballot would be binding on the decision to move the revisions to the BOD or not);
- c. ~~propose~~Propose additional changes and repeat the posting for further comment;
- d. ~~remand~~Remand the proposal to the requester for further work; or
- e. ~~reject~~Reject the proposal.

The SPM shall post any proposed revisions submitted for BOD adoption for a period of 30 days prior to BOD action. The SC shall submit to the BOD a description of the

basis for the procedure changes, a summary of the comments received, and any minority views expressed in the comment process. The proposed procedure revisions will be effective upon BOD adoption, or another date designated by the BOD.

Five-Year Review

~~Each~~The standards process manual and each MRO Regional Reliability Standard shall be reviewed at least once every five (5) years from the effective date ~~of the standard or the latest revision to the standard~~or when it was reviewed last, whichever is the later. The review process shall be conducted by soliciting comments from the stakeholders. If no changes are warranted, the SC shall recommend to the BOD that the Standard or manual be reaffirmed. If the review indicates a need to revise or withdraw the standard or manual, a SAR shall be prepared and submitted ~~by~~to the ~~SC or any other stakeholder in accordance with the standards process SPM.~~ The SPM shall be responsible for administration of the five (5)~~-~~year review of the standards process manual and the MRO Regional Reliability Standards.

On-line Standards Information System

The SPM shall be responsible for maintaining an electronic database of information regarding currently proposed and currently in effect MRO Regional Reliability Standards. This information shall include current standards in effect, proposed revisions to standards, and proposed new standards. This information shall provide a record, for at a minimum the previous five years, of the review and approval process for each MRO Regional Reliability Standard, including public comments received during the development and approval process. This information shall be available through public Internet access.

Archived Standards Information

The SPM shall be responsible for maintaining an historical record of MRO Regional Reliability Standards information that is no longer maintained on-line. Archived information of previously approved standards and version history shall be retained indefinitely as practical, but in no case less than five years or one complete standard review cycle from the date on which the standard was no longer in effect. Archived records of standards information shall be available electronically within 30 days following the receipt by the SPM of a written request.

Numbering System

The SPM shall establish, maintain, and electronically post a system of identification numbers that allow MRO Regional Reliability Standards to be categorized and easily referenced. Re-numbering of approved standards does not warrant standard review but will be handled through the SC. The SPM will notify the MRO region and post the information on the RSVP system prior to making the change.

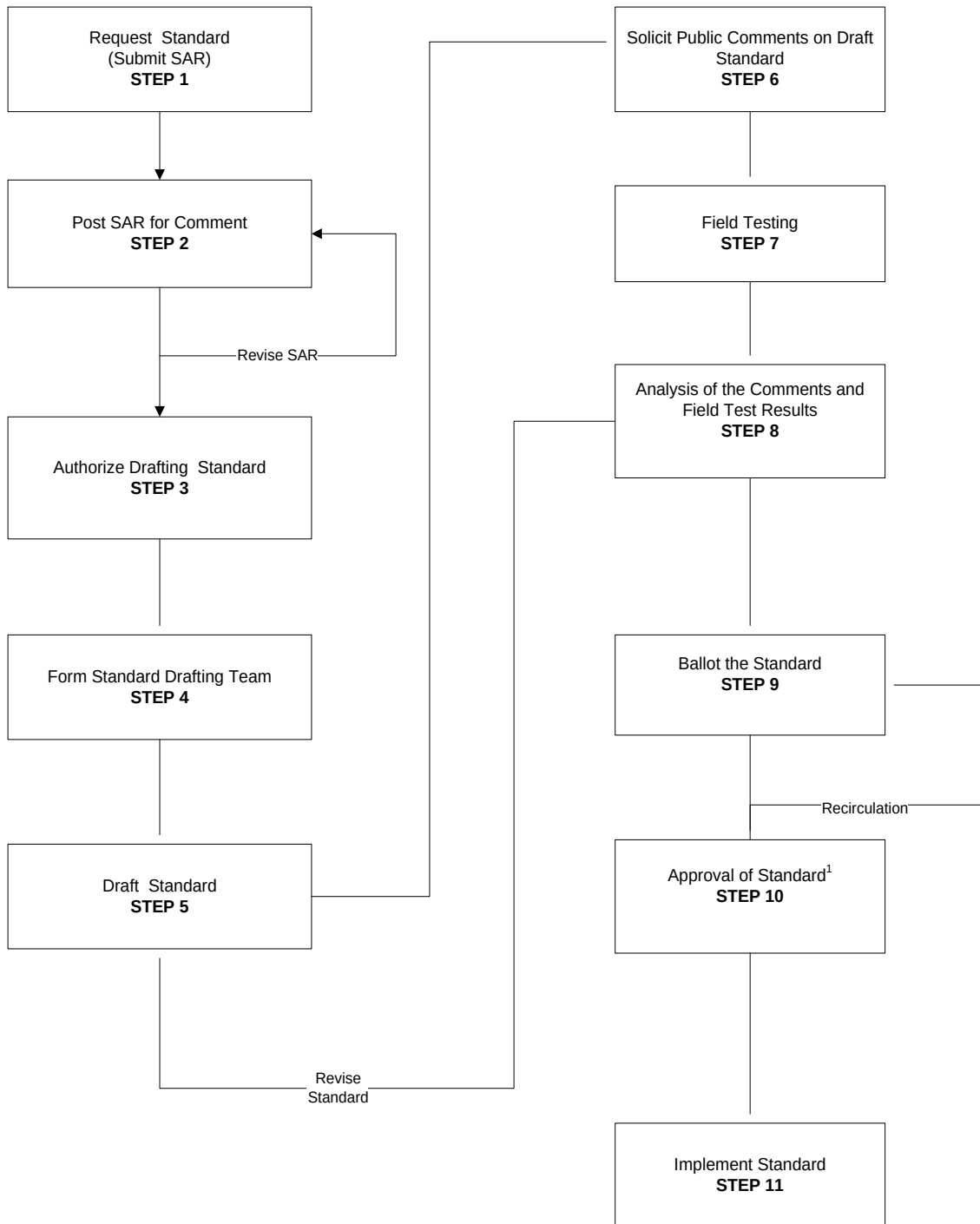
Supporting Documents

The following table identifies documents that may be developed to support a MRO Regional Reliability Standard. These documents may explain or facilitate implementation of standards but do not themselves contain mandatory requirements subject to compliance review. Any requirements that are mandatory must be

incorporated into the standard. For example, a procedure that must be followed as written must be incorporated into a MRO Regional Reliability Standard. If the procedure defines one way, but not necessarily the only way, to implement a standard it is more appropriately a reference.

Type of Document	Description	Approval
Standard Reference	Descriptive, explanatory information to support the understanding and interpretation of an MRO Regional Reliability Standard.	SC
Standard Supplement	Data forms, pro forma documents, and associated instructions that support the implementation of an MRO Regional Reliability Standard.	As assigned to the MRO Standing Committee
Procedure	Instructions defining a particular process or operation. Procedures may support the implementation of an MRO Regional Reliability Standard.	As assigned to the MRO Standing Committee
Technical Reference	Descriptive, technical information or analysis. A technical reference may support the implementation of an MRO Regional Reliability Standard.	As assigned to the MRO Standing Committee
<u>Guideline</u>	<u>Recommended process that identifies a method of meeting a requirement under specific conditions. A guideline may support the implementation of an MRO Regional Reliability Standard.</u>	<u>SC</u>

Appendix A – MRO Regional Reliability Standards Process Diagram



¹After MRO Board approval, the standard is submitted to NERC for approval and filing to the applicable regulatory authorities. Upon regulatory acceptance or approval, the standard becomes enforceable as a Reliability Standard.

Appendix B – Information in a Standard Authorization Request

Below is a template of the required information to complete a Standard Authorization Request. The SPM shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards process.

Standard Authorization Request Form

Assigned
SAR Label: (for in office use only)

Title of Proposed Standard _____

Request Date _____

SAR Requestor Information	SAR Type (Check a box for each one that applies.)	
Name _____	☐	New ~~Standard~~ standard
Primary Contact _____	☐	Revision ~~to~~ or withdraw of an existing ~~Standard~~ standard
Telephone _____ Fax _____	☐	~~Withdrawal~~ Interpretation of an existing ~~Standard~~ standard
E-mail _____	☐	Urgent ~~Action~~ action
	☐	Other

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
☐	Reliability Authority Coordinator	~~Ensures Responsible for the real-time operating reliability of the bulk transmission system within its Reliability Authority area. This is the highest Reliability Authority and in coordination with its neighboring reliability coordinator's wide-area view.~~
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced ~~Interchange Schedules~~ <u>interchange schedules</u> .
☐	Planning Authority Coordinator	~~Plans the Bulk Electric System. Assess the longer-term reliability of its area and neighboring area.~~
☐	Resource Planner	Develops a long-term (>one year) plan for the resource adequacy of specific loads within a ~~Planning Authority~~ <u>planning coordinator's</u> area.
☐	Transmission Planner	Develops a long-term (>one year) plan for the reliability of transmission systems within its portion of the ~~Planning Authority~~ <u>planning coordinator</u> area.
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐	Transmission Owner	Owns transmission facilities.
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders.
☐	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.
☐	Generator Owner	Owns and maintains generation unit(s).
☐	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and ~~Interconnected Operations Services~~ <u>interconnected operations services</u> .
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity, and all necessary ~~Interconnected Operations Services~~ <u>interconnected operations services</u> as required.
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.

☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user.

NERC Reliability and Market Interface Principles

Applicable Reliability Principles (Check box for all that apply.)	
☐	1. Interconnected bulk ~~electric~~ power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk ~~electric~~ power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk ~~electric~~ power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk ~~electric~~ power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk ~~electric~~ power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk ~~electric~~ power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk ~~electric~~ power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
Does the proposed ~~Standard~~standard comply with all of the following Market Interface Principles? (Select 'yes' or 'no' from the drop-down box.)	
1.	The planning and operation of bulk ~~electric~~ power systems shall recognize that reliability is an essential requirement of a robust North American economy. ~~Yes~~ Yes
2.	A MRO ~~Regional Reliability Standard~~ regional reliability standard shall not give any market participant an unfair competitive advantage. ~~Yes~~ .Yes
3.	A MRO ~~Regional Reliability Standard~~ regional reliability standard shall neither mandate nor prohibit any specific market structure. ~~Yes~~ Yes
4.	A MRO ~~Regional Reliability Standard~~ regional reliability standard shall not preclude market solutions to achieving compliance with that ~~Standard~~ . ~~Yes~~ standard. Yes
5.	A MRO ~~Regional Reliability Standard~~ regional reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. ~~Yes~~ Yes

Related Standards

Standard No.	Explanation
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____

Related SARs

SAR ID	Explanation
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____

Regional Differences

Region	Explanation
~~ERCOT~~ IRE	_____
FRCC	_____
MRO	_____
NPCC	_____
SERC	_____
RFC	_____
SPP	_____
WECC	_____

Appendix C – MRO Regional Reliability Standard Example

Below is an example of a MRO Regional Reliability Standard. Please see the ~~NERC Reliability Standards Development Procedure~~ NERC Regional Reliability Standards Evaluation Procedure for the most current format.

Identification Number	A unique identification number assigned by the SPM.
Title	A brief, descriptive phrase identifying the topic of the MRO Regional Reliability Standard.
Applicability	Clear identification of the functional classes of entities responsible for complying with the standard, noting any specific additions or exceptions. <u>If not applicable to the entire MRO area, then a clear identification of the portion of the bulk power system to which the standard applies. Any limitation on the applicability of the standard based on electric facility requirements should be described.</u>
Effective Date and Status	The effective date of the MRO Regional Reliability Standard shall be upon NERC and regulatory approvals. The status of the standard will be indicated as active or by reference to one of the numbered steps in the standards process.
Purpose	The purpose of the MRO Regional Reliability Standard shall explicitly state what outcome will be achieved by the approved Reliability Standard. The purpose is agreed to early in the process as a step toward obtaining approval to proceed with the development of the Reliability Standard. The purpose should link the standard to the relevant principle(s).

Requirement(s)	Explicitly stated technical, performance, preparedness, or certification requirements. Each requirement identifies who is responsible and what action is to be performed or what outcome is to be achieved. Each statement in the requirements section shall be a statement for which compliance is mandatory. <u>Several types of requirements may exist, each with a different approach to measurement:</u> • <u>Performance-based requirements define a specific reliability objective or outcome that has a direct, observable effect on the reliability of the bulk power system, i.e., an effect that can be measured using power system data or trends.</u> • <u>Risk-based requirements define actions of entities that reduce a stated risk to the reliability of the bulk power system and can be measured by evaluating a particular product or outcome resulting from the required action.</u> • <u>Capability-based requirements define capabilities needed to perform reliability functions and can be measured by demonstrating that the capability exists as required.</u> Any additional comments or statements for which compliance is not mandatory, such as background or explanatory information, should be placed in a separate document and referenced (see Supporting References).

Violation Risk Factors	The potential reliability significance of each requirement, designated as a High, Medium, or Lower Risk Factor in accordance with the criteria listed below: A High Risk Factor requirement (a) is one that, if violated, could directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures, or could place the bulk power system at an unacceptable risk of instability, separation, or cascading failures; or (b) is a requirement in a planning timeframe that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures, or could place the bulk power system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. A Medium Risk Factor requirement (a) is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures; or (b) is a requirement in a planning timeframe that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk power system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is 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 affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system.

Measure(s)	Each requirement shall be addressed by one or more measures. These measures will be used to assess performance and outcomes for the purpose of determining compliance with the requirements stated above. Each measure shall identify to whom the measurement applies and the expected level of performance or outcomes required demonstrating compliance. Each measure shall be tangible, practical, and as objective as is practical. It is important to realize that measures are proxies to assess required performance or outcomes. Achieving the full compliance level of each measurement should be a necessary and sufficient indicator that the requirement was met. Each measure shall clearly refer to the requirement(s) to which it applies.

Glossary of Terms Used in Standards

Definitions of Terms:	All defined terms used in MRO Regional Reliability Standards, shall be defined in the glossary. Definitions may be approved as part of a standards action or as a separate action. All definitions must be approved in accordance with the standards process.

Compliance Administration Elements

Compliance Monitoring Process	The following compliance elements, which are part of the standard and are balloted with the standard are developed for each measure in a standard by the NERC compliance program in coordination with the standard drafting team • The specific data or information that is required to measure performance or outcomes. • The entity that is responsible for providing the data or information for measuring performance or outcomes. • The process that will be used to evaluate data or information for the purpose of assessing performance or outcomes • The entity that is responsible for evaluating such data or information. • The time period in which performance or outcomes is measured, evaluated, and then reset. • Measurement data retention requirements and assignment of responsibility for data archiving.
Violation Severity Levels	Defines the degree to which compliance with a requirement was not achieved. The violation severity levels, are part of the standard and are balloted with the standard, and developed by the MRO compliance program in coordination with the standard drafting team.

Supporting Information Elements

Interpretations	Formal interpretations of Regional Reliability Standard(s) proposed by the MRO and approved by NERC, FERC, and the applicable Canadian regulatory authorities. Interpretations are temporary, as the standard should be revised to incorporate the interpretation.
Implementation Plan	Each Regional Reliability Standard proposed by the MRO and approved by NERC, FERC and the applicable Canadian regulatory authorities shall have an associated implementation plan describing the effective date of the standard or effective dates if there is a phased implementation. The implementation plan may also describe the implementation of the standard in the compliance program and other considerations in the initial use of the standard, such as necessary tools, training, etc. The implementation plan must be posted for at least one public comment period and is approved as part of the ballot of the standard.
Supporting References	This section will reference related documents that support implementation of the Reliability Standard proposed by the MRO and approved by NERC and the regulatory authorities, but are not themselves mandatory. Examples include, but are not limited to: • Developmental history of the standard and prior versions • Notes pertaining to implementation or compliance • Standard references • Standard supplements • Procedures • Practices • <u>Guidelines</u> • Training references • Technical references • White papers • Internet links to related information
<u>Data Retention</u>	<u>Each Regional Standard shall identify the data retention requirements and assignment of responsibility for data archiving.</u>
<u>Mitigation Time Horizon</u>	<u>Each Regional Standard shall reference a mitigation time horizon (long-term planning; operations planning; same-day operations; real-time operations and operations assessment) for each requirement.</u>
<u>Regulatory Directives</u>	<u>Each Regional Standard shall be consistent with Regulatory Directives, if applicable.</u>
<u>NERC Reliability Standards</u>	<u>Each Regional Standard shall be consistent with related NERC reliability standards, as applicable.</u>

Appendix D – Registered Ballot Body (RBB) Registration Procedures

The RBB comprises all organizations and entities that:

1. qualify for one of the segments, and
2. are registered with MRO as ballot participants in the voting on standards, and
3. are current with any MRO designated fees associated with this program. Designated fees are defined as fees associated with the Standards Development process. At this time there are no fees for registration.

Each entity, when initially registering to join the RBB, and ~~annually thereafter,~~ will self-select to belong to one or more of the segments described below.

The SPM shall review all applications for joining the RBB, and make a determination of whether the self-selection satisfies at least one of the guidelines to belong to that segment. The entity will then be “credentialed” to participate as a voting member of that segment. The SC will decide disputes, with an appeal to the BOD.

In order to comment or vote you must have an active membership in the RBB. When you submit your registration request, you are placed in a “pending stage” until your account is activated. Activation of your account may take up to 24 hours. You will be unable to submit comments or vote until your account is activated.

All registrations must be done electronically via the RSVP application (<http://rsvp.midwestreliability.org>). There is no fee for registration at this time.

Segment Qualification Guidelines

The segment qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the electric industry that can meet any one of the guidelines for a segment is entitled to belong to and vote in that segment. Only one vote per entity per segment is permitted.

The general guidelines for all segments are:

- Corporations or organizations with integrated operations or with affiliates that qualify to belong to more than one segment (e.g., Transmission Owners and Load Serving Entities) may belong to each of the segments in which they qualify, provided that each segment constitutes a separate membership in the RBB and is represented by a different representative. Only one vote per entity per segment registered is allowed.
- Corporations, organizations, and entities may participate freely in all subgroups.
- After their initial selection, registered participants may apply to change segments with thirty (30) days notice to the SPM. In addition, a registered participant cannot change segments during a balloting period once the participant has cast a vote or designated a proxy.

- Additionally, the SPM may change a participant segment under certain circumstances. These circumstances will be approved by the SC and posted on the RSVP.
- The qualification guidelines and rules for joining segments, as listed below, will be reviewed periodically by the SC to ensure that the process continues to be fair, open, balanced, and inclusive. Public input shall be solicited in the review of these guidelines.
- Since all balloting of standards will be done electronically, any registered participant may designate an agent or proxy to vote on its behalf. There are no limits on how many proxies an agent may hold. However, the MRO must have in its possession, either in writing or by e-mail, documentation that the voting right by proxy has been transferred from the registered participant to the agent prior to casting any vote.

Segments

Segment 1: Transmission Owners

- a. Any entity within the MRO region that owns or controls at least 200 circuit miles of integrated transmission facilities, or has an Open Access Transmission Tariff or equivalent on file with a regulatory authority.
- b. Transmission owners within the MRO region that have placed their transmission under the operational control of an RTO.
- c. Independent transmission companies or organizations, merchant transmission developers, and transmission companies (TRANSCOs) that are in the MRO region and are not RTOs.
- d. Excludes RTOs, RCs and ISOs (that are eligible to belong to Segment 2).

Segment 2: Regional Transmission Organizations (RTOs), Regional Transmission Group (RTG), Independent System Operators (ISOs), Reliability Organizations, and Reliability Coordinators

- a. Authorized by appropriate regulator to operate as an RTO, RTG, or ISO within or adjacent to ~~the~~ MRO.
- b. Reliability Organizations certified by NERC or its successor.

~~e. Check FERC definition.~~

~~d.c.~~ Reliability Coordinators within or adjacent to ~~the~~ MRO.

~~e.d.~~ In cases where the RTO or ISO and the RC have exactly the same geographic boundary, both may belong to this segment as long as they are separate entities.

e. A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate

transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Segment 3: Load-Serving Entities (LSEs)

- a. Entities within the MRO region serving end-use customers under a regulated tariff, a contract governed by a regulatory tariff, or other legal obligation to serve.
- b. A member within the MRO region of a generation and transmission (G&T) cooperative or a joint-action agency is permitted to designate the G&T or joint-action agency to represent it in this segment; such designation does not preclude the G&T or joint-action agency from participation and voting in another segment representing its direct interests.

Segment 4: Electric Generators

- a. Affiliated and independent generators within the MRO region.
- b. A corporation that sets up separate corporate entities for each one or two generating plants within the MRO region in which it is involved may only have one vote in this segment regardless of how many single-plant or two-plant corporations the parent corporation has established or is involved in.

Segment 5: Electricity Brokers, Aggregators, and Marketers

- a. Entities serving end-use customers under a power marketing agreement or other authorization not classified as a regulated tariff.
- b. An entity that buys, sells, or brokers energy and related services for resale in wholesale or retail markets, whether a non-jurisdictional entity operating within its charter or an entity licensed by a jurisdictional regulator.
- c. G&T cooperatives and joint-action agencies that perform as an electricity broker, aggregator, or marketer function are permitted to belong to this segment.

Segment 6: Electricity End Users

- a. Service delivery taken within the MRO region that is not purchased for resale.
- b. Agents, associations, consumer advocates can represent groups of end users or a transmission dependent utility. A Transmission Dependent Utility (TDU) is defined as; an entity that relies on another entity for transmission service to service the majority of their contractual loads.

Segment 7: Federal, State, and Provincial Regulatory or other Government Entities

- a. Does not include Power Marketing Administration or Federal Power Marketing Agency (PMAs) or Tennessee Valley Authority (TVA-).

- b. May include Public Utility Commissions (PUCs-).

Appendix E – Balloting Examples

The MRO voting mechanism differs from NERC in that a quorum is established if at least four Segments have submitted an affirmative, negative or abstention vote. A majority vote within a Segment is determined based on the affirmative and negative votes. A Standard is approved if at least two-thirds of the voting Segments have an affirmative vote. The following are examples of potential voting scenarios. The yellow areas indicate where a Segment did not cast a vote. The green areas with **bold** numbers represent majority votes within a Segment.

Example RBB

Segment	Number Registered in the RBB
1. Transmission Owners	15
2. RTO's, ISO's, RRO's & Reliability Coordinators	4
3. Load Serving Entities	16
4. Electric Generators	21
5. Electricity Brokers, Aggregators, & Marketers	7
6. Electricity End Users	6
7. Federal, State, & Provincial Regulatory or other Government Entities	8
Totals	77

Example 1 – A quorum has been established with 5 of the 7 Segments having registered an affirmative, negative, or an abstention vote. Two-thirds of the Segments (4 of 5 voting Segments) have voted to approve the Standard. The Standard is approved.

Segment	Ballot Pool	Votes			
		Affirmative Votes	Negative Votes	Abstain Votes	No Ballot
1. Transmission Owners	15	10	2	1	2
2. RTO's, ISO's, RRO's & Reliability Coordinators	4	3	0	0	1
3. Load Serving Entities	16	3	6	2	5
4. Electric Generators	21	13	0	1	7
5. Electricity Brokers, Aggregators, & Marketers	7	0	0	0	7
6. Electricity End Users	6	0	0	0	6
7. Federal, State, & Provincial Regulatory or other Government Entities	8	3	0	1	4
Totals	77				

Example 2 – A quorum has been established with 4 of the 7 Segments having registered an affirmative, negative, or an abstention vote. Less than two-thirds of the Segments (1 of 4 voting Segments) have voted to approve the Standard. The Standard is NOT approved.

Segment	Ballot Pool	Votes			
		Affirmative Votes	Negative Votes	Abstain Votes	No Ballot
1. Transmission Owners	15	10	2	1	2
2. RTO's, ISO's, RRO's & Reliability Coordinators	4	1	2	0	1
3. Load Serving Entities	16	3	6	2	5
4. Electric Generators	21	0	0	0	21
5. Electricity Brokers, Aggregators, & Marketers	7	0	0	0	7
6. Electricity End Users	6	0	0	0	6
7. Federal, State, & Provincial Regulatory or other Government Entities	8	0	3	1	4
Totals	77				

Example 3 – A quorum has not been established because only 3 of the 7 Segments have registered an affirmative, negative, or an abstention vote. The Standard is NOT approved because of a lack of a quorum.

Segment	Ballot Pool	Votes			
		Affirmative Votes	Negative Votes	Abstain Votes	No Ballot
1. Transmission Owners	15	10	2	1	2
2. RTO's, ISO's, RRO's & Reliability Coordinators	4	4	0	0	0
3. Load Serving Entities	16	3	6	2	5
4. Electric Generators	21	0	0	0	21
5. Electricity Brokers, Aggregators, & Marketers	7	0	0	0	7
6. Electricity End Users	6	0	0	0	6
7. Federal, State, & Provincial Regulatory or other Government Entities	8	0	0	0	8
Totals	77				

Example 4 – A quorum has been established with 6 of the 7 Segments having registered an affirmative, negative, or an abstention vote. The Standard is NOT approved because two-thirds of the Segments did not cast an affirmative vote. Segment 2's vote is considered negative because a majority did not cast an affirmative vote.

Segment	Ballot Pool	Votes			
		Affirmative Votes	Negative Votes	Abstain Votes	No Ballot
1. Transmission Owners	15	10	2	1	2
2. RTO's, ISO's, RRO's & Reliability Coordinators	4	2	2	0	0
3. Load Serving Entities	16	3	6	2	5
4. Electric Generators	21	10	9	1	1
5. Electricity Brokers, Aggregators, & Marketers	7	4	3	0	0
6. Electricity End Users	6	0	0	0	6
7. Federal, State, & Provincial Regulatory or other Government Entities	8	2	3	0	3
Totals	77				

From: [Jennifer L. Matz](#)
To: [Lee R. Pedowicz](#)
Cc: [William S. Smith](#)
Subject: [rsvp-users] FW: (Reminder): Version 5 of the MRO Standards Process Manual will be open for 10-day ballot period
Date: Thursday, April 12, 2012 3:35:49 PM
Attachments: [SPM Announcement of 10-day ballot period 03302012.pdf](#)

RSVP Users,

This is a reminder that the 10-day ballot period for Version 5 of the MRO Standards Process Manual begins tomorrow April 13, 2012 and ends on April 23, 2012. Please see the email below that was recently sent to MRO stakeholders about the ballot period. The RSVP users email list receives announcements from the mro-all. However, I wanted to know for sure the RSVP users received the reminder.

Feel free to contact me with questions.

Thank you.

Jennifer Matz

Compliance, Mitigation & Standards Administrator

Midwest Reliability Organization

2774 Cleveland Ave North

Roseville, MN 55113

Ph: 651-855-1740 Fx: 651-855-1712

www.midwestreliability.org

MRO is moving! As of April 30, our new address will be 380 St. Peter Street, Ste. 800, St. Paul, MN 55102. (Our phone and email addresses will not change.) Please update your records accordingly.

NOTICE:

This e-mail and any of its attachments may contain MRO or NERC proprietary information that is privileged, confidential, or subject to copyright belonging to MRO or NERC. This e-mail is intended solely for the use of the individual or entity to which it is addressed. If you are not the intended recipient you are hereby notified that any dissemination, distribution, copying, or action taken in relation to the contents of and attachments to this e-mail is strictly prohibited and may be unlawful. If you have received this message in error, please notify the sender immediately and permanently delete the original and any copy of this e-mail.

From: Jennifer L. Matz
Sent: Thursday, April 12, 2012 1:31 PM
To: mro-all@midwestreliability.org

Subject: FW: (Reminder): Version 5 of the MRO Standards Process Manual will be open for 10-day ballot period

Greetings,

On Friday, March 30, 2012, MRO notified stakeholders about a 10-day ballot period opening up for Version 5 of the MRO Standards Process Manual. This email is a reminder that the 10-day ballot period begins tomorrow April 13, 2012 and ends on April 23, 2012. The ballot will take place via the [RSVP application](#). Please make sure you are registered on the RSVP application in order to submit your vote; votes are to only be submitted by one person per company, per segment.

Please note: An updated redline is posted on RSVP identifying all the edits made from the MRO Board of Directors approved version 4.5 to version 5.0 of the MRO Standards Process Manual.

Feel free to contact me with questions.

Thank you,

Jennifer Matz

Compliance, Mitigation & Standards Administrator

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From: Jennifer L. Matz

Sent: Friday, March 30, 2012 4:39 PM

To: mro-all@midwestreliability.org

Cc: mrosc-mem@midwestreliability.org

Subject: Version 5 of the MRO Standards Process Manual will be open for 10-day ballot period

Greetings,

The following attachment is sent on behalf of Will Smith, MRO Manager of Standards and Program Performance.

Thank you,

Jennifer Matz

Compliance, Mitigation & Standards Administrator

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Roseville, MN 55113

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You are currently subscribed to rsvp-users as: lpedowicz@npcc.org.

To unsubscribe click here: <http://listman.midwestreliability.org/u?id=2550.85353d3b2f39b9c9b5ee3576578c04b7&n=T&l=rsvp-users&o=92019>

(It may be necessary to cut and paste the above URL if the line is broken)

or send a blank email to leave-92019-2550.85353d3b2f39b9c9b5ee3576578c04b7@midwestreliability.org

From: [Philip A. Fedora](#)
To: [grpStaff](#)
Subject: FW: GOVERNOR CUOMO ANNOUNCES NEXT MAJOR STEP IN BUILDING THE NEW YORK ENERGY HIGHWAY
Date: Wednesday, April 11, 2012 4:32:20 PM

FYI - Phil

From: NYEnergyHighway [mailto:NYEnergy.Highway@nypa.gov]
Sent: Wednesday, April 11, 2012 4:27 PM
To: Philip A. Fedora
Subject: GOVERNOR CUOMO ANNOUNCES NEXT MAJOR STEP IN BUILDING THE NEW YORK ENERGY HIGHWAY



STATE OF NEW YORK | EXECUTIVE CHAMBER
ANDREW M. CUOMO | GOVERNOR

For Immediate Release: April 11, 2012

GOVERNOR CUOMO ANNOUNCES NEXT MAJOR STEP IN BUILDING THE NEW YORK ENERGY HIGHWAY

Request for Information Released; Conference of Interested Parties to Follow on April 19

Governor Andrew M. Cuomo today announced that his New York Energy Highway Task Force has issued a Request for Information (RFI) seeking ideas for potential projects from private developers, investor-owned utilities, the financial community, and others with the goal of bolstering New York State's aging energy infrastructure while promoting clean energy supplies, jobs, and economic growth. This marks a key milestone in Governor Cuomo's plans, announced at the 2012 State of the State, to construct a 21st century energy highway in New York State.

The RFI is available on the Energy Highway website: www.nyenergyhighway.com. Responses to the request are due on May 30.

A conference for respondents and other interested parties will be held on Thursday, April 19 from 1:00 to 3:00 p.m. at the DoubleTree Hotel in Tarrytown. Advance registration is required as space is limited. Those planning to attend should e-mail info@nyenergyhighway.com.

"Building a new energy highway for New York State will not only create thousands of jobs, but lay a new foundation for future economic growth," Governor Cuomo said. "If we want to truly make New York State open for the businesses of tomorrow, we cannot rely on the power supply of yesterday. We have transformed state government to make it a partner for private sector job growth and the energy highway is a prime example of how state government is now partnering

with the private sector to create jobs and generate economic growth."

The RFI seeks detailed information on various aspects of potential electric generation and transmission projects, including such areas as financing, construction, operation, and economic and environmental benefits. Respondents are also invited to identify potential challenges to project development that could be addressed with state assistance. Written questions will be accepted and answered on the website through May 11, with the names of the questioners deleted.

The Governor's Task Force will issue an Energy Highway Action Plan this summer, following its review of the RFI responses. The action plan, with the Task Force's recommendations, will be available to the public on the Energy Highway website.

On April 4, the Task Force, comprising the heads of the state's principal energy, environmental, and economic development agencies, set the stage for the initiative by holding an Energy Highway Summit at Columbia University. More than 500 attendees heard from national and state leaders in the electric power industry and in the financial, regulatory, and academic communities.

In his 2012 State of the State Address, Governor Cuomo outlined his vision for the Energy Highway, including projects that would enable delivery of economical surplus power from upstate sources and new renewable power generation to the downstate region, where the need is greatest.

The Governor appointed the Task Force to implement the Energy Highway initiative, naming as Co-Chairs Gil C. Quiniones, President and Chief Executive Officer of the New York Power Authority, and Joseph Martens, Commissioner of the New York State Department of Environmental Conservation. The other Task Force members are Kenneth Adams, President, Chief Executive Officer and Commissioner of Empire State Development; Garry A. Brown, Chairman of the New York State Public Service Commission; and Francis J. Murray, Jr., President and Chief Executive Officer of the New York State Energy Research and Development Authority.

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Additional news available at www.governor.ny.gov
New York State | Executive Chamber | press.office@exec.ny.gov | 518.474.8418

April 5, 2012

Mr. Scott Helyer, Chair
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:

Congratulations on your first meeting as chair of the Member Representatives Committee (MRC). The Board greatly appreciated the active engagement of committee members in all of the discussions, along with the prepared policy inputs provided to the Board in advance of the meeting.

I have identified below three items on which the Board will be particularly interested in policy input from the MRC members for the upcoming meetings in May. As always, the Board also welcomes input on any other issues that stakeholders wish to provide. I understand the agendas for the MRC and Board meetings are expected to be posted by April 25.

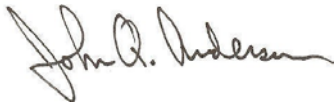
Standards Process Input Group — The Board looks forward to hearing from the MRC Standards Process Input Group (SPIG) on their findings and policy recommendations for improving the existing NERC standards development process and to active discussion of these recommendations by the entire MRC.

2013 NERC and Regional Entity Common Business Plan and Budget Assumptions — NERC and the Regional Entities jointly developed Common Business Plan and Budget Assumptions for the 2013-2015 planning period and posted them for comment on February 21, 2012. The assumptions are being updated in response to comments received from EEI, which have also been posted on the NERC website. Additional comments on the common assumptions are welcome, and will be appropriately considered in business plan and budget review and approval process. As always, it will be most helpful if these comments are as specific as possible. In addition, since the actual draft business plan and budget document will be released after the agendas are posted but prior to the MRC meeting, there will be an opportunity to discuss it at the MRC meeting, thereby providing additional input to the Board.

Definition of Adequate Level of Reliability — As part of the request to the MRC to provide policy input to the Board on the definitions of Bulk Electric System (BES) and Adequate Level of Reliability (ALR), a task force of the Planning, Operating, Critical Infrastructure Protection and Standards Committees has been working on the definition of ALR (see [ALR Task Force website](#)) and expects to post by the end of April for industry review and comment a draft definition document, a supporting technical reference document, a discussion paper on risk tolerance, and a mapping of ALR reliability objectives to NERC's Reliability Principles. While we are still not at the stage where the Board will be asked to take action, we would welcome any initial comments and discussion by the MRC members.

Thank you in advance for providing written comments to Holly Mann, MRC Secretary (holly.mann@nerc.net) **by May 1, 2012** so they can be sent to the Board for review 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



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

BOARD OF DIRECTORS AGENDA

Tuesday, May 1, 2012

10:00 a.m. – 1:00 p.m.

Meeting via Teleconference

Dial-In: 877-260-3999

Code: 6945#

-
1. Introductions/Quorum/Antitrust Compliance Guidelines	10:00
2. President's Report	10:05
3. Report by the Treasurer	10:15
a) Finance and Audit Committee Activities	
b) Annual Independent Audit of Financial Statements	
4. Consideration of draft NPCC Board of Directors Minutes	10:25
a) March 13, 2012 Teleconference Meeting	<i>[Action Required]</i>
5. Membership and Committee Changes	10:30
a) NPCC Membership Changes	
b) Committee Reports and Corporate Goals Scorecard (written reports only)	
c) RSC, CC, RCC, PIC Membership	<i>[Action Required]</i>
6. Administrative Matters	10:40
a) 2012 Management Salary Bandwidths	<i>[Action Required]</i>
7. Summer 2012 Reliability Assessment	10:50
a) Operating Security Analyses and Probabilistic Assessment	
8. NERC Member Representatives Committee and Board of Trustees	11:30
– May 8-9, 2012 <i>Agenda to be distributed by NERC at the end of April</i>	
a) Preliminary NERC 2013 Business Plan and Budget	
b) NPCC BOD Policy Input	<i>[Action Required]</i>
9. Organizational Matters	12:15
a) Preliminary 2013 NPCC Budget	
10. 2012 Board of Director Meeting Dates	12:30
• Tuesday, June 26, 2012 – NPCC Offices (10 a.m. – 5 p.m.)	
• Tuesday, August 7, 2012 – Teleconference (10 a.m. – 1 p.m.)	
• Wednesday, September 19, 2012 – NPCC Offices (10 a.m. – 5 p.m.)	
• Tuesday, October 30, 2012 – Teleconference (10 a.m. – 1 p.m.)	
• Wednesday, November 28, 2012 – Montreal, Québec (7:30 a.m. – 10 a.m.)	



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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 – Transmission 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 Board of Directors
May 1, 2012
Agenda Item #2.*

President's Report

May 1, 2012

Board of Directors Meeting

Report Items:

- **FERC Audit Status**
- **NERC FFT Initiative – Request for Rehearing**
- **NERC FFT Initiative – Removal of Unnecessary Requirements**



*NPCC Board of Directors
May 1, 2012
Agenda Item #3.*

Report by the Treasurer

May 1, 2012

Board of Directors Meeting



Report Items:

- Finance and Audit Committee Activities
- PWC Independent Audit Report for 2011



Northeast Power Coordinating Council, Inc. Board of Directors Meeting Draft Minutes for Approval

March 13, 2012 | 10:03 a.m.
(via teleconference)

The Chairman called to order a duly noticed meeting of the Board of Directors (*Board*) of Northeast Power Coordinating Council, Inc. (*NPCC*) held via teleconference on March 13, 2012, at 10:03 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

At the Chairman's request, a motion to waive the reading of the *NPCC Antitrust Compliance Guidelines* that were distributed via email with the Board agenda package 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 draft minutes of the Board meeting held on February 1, 2012, which incorporated comments previously submitted. A motion to approve the minutes, as revised, of the NPCC Board of Directors meeting held on February 1, 2012 was duly made, seconded and approved by the Directors in each active Sector of the Board.

The President and CEO noted that there were two action items following the January 31st Board Strategy Session and the February 1st Board Meeting. The Vice President and COO reported on the first item in response to a director's request for an analysis of the savings reported by management in 2011 due to meetings held via teleconference compared with the higher time and travel costs associated with conducting in-person meetings. She noted that as a result of significant use of meetings held via teleconference more than 8,850 hours were spent on NPCC teleconference meetings during 2011. She continued that nearly 6,000 participants engaged in NPCC teleconferences rather than going to in person meetings during 2011. The Chairman then reported on the second item and indicated that in response to the Board's request for NPCC's standing committees to present formal reports to the Board on a predictable schedule throughout the year, the following has been proposed:

- June 26, 2012 Board meeting – Pension Committee
- September 19, 2012 Board meeting – Management Development & Compensation Committee (MDCC)
- November 28, 2012 Board meeting – Corporate Governance & Nominating Committee (CGNC)
- Late January or early February 2013 Board meeting – Finance & Audit Committee (FAC)

There were no questions from Board members regarding the proposed schedule.

Status of Bulk Electric System (*BES*) Definition Activities

The President and CEO presented a brief BES Definition status update, which covered four (4) items:

- *Regulatory Status* – On January 25, 2012, the revised BES Definition and Rules of Procedures had been filed by NERC with FERC. Notifications of these filings were sent to Ontario, New

Brunswick, and Québec on March 1, 2012. The President indicated that NERC's expectation is that FERC may act during the third quarter of 2012.

- *NPCC Data Survey* – On January 26, 2012, NPCC sent a data survey to 290 registered entities in its U.S. footprint that was designed to determine the impact of the BES Definition in the NPCC Region. An informational copy of the survey was also sent to NPCC's registered entities in Canada. The data survey is a self-assessment that asks the registered entities to identify elements that would meet the BES Definition and seeks to identify potential exception candidates. The President continued that more than 200 entities had participated in NPCC's Bulk Electric System Data Request webinar held on March 2, 2012. Survey responses should be prepared by March 26th, with minimal exceptions anticipated, which is a testament to the excellent work performed by NPCC.
- *Development of Consistent Regional BES Exception Process* – NPCC, in conjunction with SERC, is leading an interregional BES Exception Process Group to develop common data specifications and data collection methodologies, and consistent technical review processes and appeals procedures. The group will promote the exchange of interregional expertise to populate Regional Entity review panels to achieve consistent interpretation and enhance acceptance rate at NERC.
- *Phase 2 Technical Activities & Standard Drafting Team Efforts* – The meeting notes for the BES Phase 2 Project meeting were previously circulated in the Board agenda package. The Standard Drafting Team is currently working on a Guidance Document for the filed BES Definition. Sub-committees of the NERC Planning Committee have been assigned to address technical issues regarding the 100 kV voltage level, the 20/75 MVA generator threshold question, reactive resource threshold level, and power flow out of local networks. Technical reviews are scheduled to be available by the end of 2012.

In response to questions from the Board, the President and CEO explained that Phase 2 was anticipated to be an 18-month project.

Overview of Board-Approved NPCC 2012 Corporate Goals

The Chairman of the Management Development and Compensation Committee (MDCC) requested that the President and CEO present the revised *2012 NPCC Corporate Goals* as most recently approved by the MDCC. The President noted that the goals were more compressed than those considered by the MDCC in January and presented during the February Board meeting and that each goal was presented in terms of its support for a specific NERC goal identified in the *Electric Reliability Organization Enterprise Strategic Plan*. He explained that the weighting for the goals was distributed as follows: 50% related to enhancing Northeast reliability, 20% related to cost-effectiveness and 30% related to NERC leadership. He further explained that for consistency with NERC, a performance goal based on overall reliability was included in the 50% weighting section so that 10% of at-risk compensation would depend on NPCC members experiencing no Category 5 events (as defined by NERC). He noted that NPCC Staff would address this goal by targeting the causes of relay mis-operations in NPCC, a topic that was recently introduced at a meeting of the Reliability Coordinating Committee. He also noted that since NPCC was undergoing a FERC audit, one of the Board members had proposed as a target goal that there should be no material deficiencies identified by FERC in its audit assessment report of NPCC by year-end 2012, and that goal had been added.

Several Board members offered comments and asked questions on the revised 2012 Corporate Goals as approved by the MDCC. In response to these inquiries, the President and CEO (i) noted that the additional outcome based objectives were incorporated into the 100% goal total, (ii) confirmed that a Member support component was implicitly incorporated into all of the goals, and (iii) explained the rationale for the financial goal as having a threshold of NPCC operating within 103% of the initial 2012 budget. The Vice President and COO further informed the Board that NPCC had never operated over its Board approved budget and FERC routinely challenged whether NPCC (as well as the other Regional Entities) were under-resourced

should unanticipated reliability requirements emerge within a given year. The President and CEO also noted, in response to a Director's question about potential passive observer type of goals, that the relay mis-operations initiative was designed to focus NPCC Members, and the neighboring Regional Entities' attention on a leading cause of major system outages.

MDCC Activities Update

The Chairman provided a brief update on the retention of a compensation consultant. He informed the Board that NPCC management had distributed a request for proposal (*RFP*) on behalf of the MDCC, and that six RFP responses had been submitted by Aon Hewitt, the Hay Group, Mercer Consulting, SMN Associates, Pay Governance, and Towers Watson, respectively. He noted that the MDCC interviewed representatives from four of the six firms, and decided to award the contract to Pay Governance, since it had the most appropriate experience, background and proposal to conduct the study~~this firm had prior experience performing compensation analyses for Reliability First Corporation, among other reliability organizations~~. He noted that fees included in the responses to the RFPs ranged from \$28,000 to \$85,000 plus expenses, and that the estimated cost~~fee~~ for the compensation study was projected to be approximately \$40,000. There were no questions following this MDCC update.

Future Meetings

The Chairman presented the schedule of Board meetings for the remainder of calendar year 2012, which was distributed via email with the Board agenda package.

Adjournment

There being no further business, the Chairman adjourned the meeting of the NPCC Board of Directors at 10:52 a.m.

Approved by Board action on _____, 2012.

Submitted by,

Andrianne S. Payson
NPCC Secretary

EXHIBIT C
LIST OF ATTENDEES
March 13, 2012

Present: Harvey J. Reed, Chairman
Edward A. Schwerdt, President and CEO
Jennifer Budd Mattiello, Vice President and COO
Andrianne S. Payson, Esq., 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
Sector 3 (TDUs, DPs, LSEs)	David H. Boguslawski, Northeast Utilities Michael Penstone, Hydro One
Sector 4 (GOs)	Andrew Barrett, Ontario Power Generation, Inc. (<i>by proxy to the President</i>) Brad Van Auken, New York Power Authority
Sector 5 (Marketers, Brokers and Aggregators)	Glen McCartney, Constellation Energy Commodities Group, Inc. (<i>by proxy to the President</i>) Daniel Whyte, Brookfield Power Generation
Sector 6 (Regulatory)	Hans Mertens, Vermont Department of Public Service Tammy Mitchell, NYS Department of Public Service
Sector 7 (Sub-Regional RCs, Customers, Other REs)	Michael Forte, New York State Reliability Council, LLC
Sector 8 (Independents)	Donald L. Correll Jan L. Newton



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NPCC MEMBERSHIP CHANGES

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Midwest Reliability Organization (MRO) has withdrawn their NPCC membership due to time constraints.



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1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 (212) 840-1070 FAX (212) 302-2782

Date: May 1, 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 based on TFCO's and TFCP's comments.
 - NPCC Directory #5 Phase II, Operating Reserve remains under development with TFCO.
 - A new Directory #6, Regional Reserve Sharing- A new Directory has recently been balloted by the NPCC Full Members and approved.
 - Directories #4 and #7 Phase II, are currently under review by TFSP and the RSC and CC are engaged in assisting with criteria related language to facilitate the CCEP program.
- The RSC, through NPCC staff, is preparing materials for recent stakeholder, NPCC BOD and NERC Board of Trustee approved NPCC UFLS Regional Standard (PRC-006-NPCC-01) to be filed with the FERC in the third quarter of 2012.
- NPCC Staff and select members of the RSC completed development of a draft NERC 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. NPCC presented the NERC CEAP to the NERC Standards Committee Process Subcommittee and Standards Committee. Further outreach has been done to the North American Transmission Forum and the North American Generator Forum and

Steering Committee. The next step is for the NERC CEAP to be posted for comment by NERC. In 2012 it is also envisioned that NPCC will assist in piloting this new CEAP within the NPCC region, by applying it to a NERC continent wide standard and sharing the results with industry and the NERC Standards Committee.

- The NPCC Reserve Sharing Group Regional Standard, BAL-002-NPCC-01, standard drafting team has been populated with members of TFCO and others. The associated NERC Project 2010-14 which contains 4 standards, BAL-001, 002, 012 and 013 are scheduled to be posted for comment on the NERC website in May 2012. NPCC will review this suite of standards to determine if there continues to be need for the regional BAL-002 standard and RSC will make a determination at that time whether the standard should proceed or continue to be held in abeyance until the NERC standards are well developed and reevaluated.
- 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 is also reviewing and finalizing a list of NPCC's more stringent criteria for inclusion in a New York State Public Service Commission filing which is a revision to the previous filing NPCC did in 2007 making NPCC's criteria mandatory in New York State by law. NPCC anticipates filing the revised criteria contained in the Directories by the end of 2012.
- NPCC Staff and a member representative of the RSC met with the Ontario Energy Board to discuss process related issues as they pertain to continent wide, regional, and NPCC's criteria.
- 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.
 - 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
 - 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 and is discussing potential alternate and efficient ways to utilize NPCC's subject matter expert resources.
 - RSC assisted and continues to assist with refinement and implementation of the NERC Prioritization tool being used to evaluate and prioritize standards projects and also participated in the drafting of the 2012-2014 Reliability Standards Development Plan.

- o 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.
 - o 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:
 - o Project 2007-09 PRC-024-1 Successive Ballot
 - o Project 2007-09 MOD-026-1 Successive Ballot
 - o Project 2007-17 PSMT Successive Ballot PRC-005-02
 - o Project 2007-17 PSMT Non-binding Poll PRC-005-02
 - o Project 2009-26 Successive Ballot CIP-004-1 WECC
 - o Project 2011-INT-02 Interpretation of VAR-002 for Constellation
 - o Project 2010-INT-05 CIP-002-1 R3 for Duke Energy
 - o Project 2006-06 Non-binding Poll IRO-001-2
 - o Project 2006-06 Non-binding Poll COM-002-3
 - o Project 2006-06 Non-binding Poll COM-001-2
 - o Project 2006-06 IRO-001-3 Initial Ballot
 - o Project 2006-06 COM-002-3 Initial Ballot
 - o Project 2006-06 Reliability Coordination COM-001-2 Initial Ballot
 - o Project 2010-07 — Generator Requirements at the Transmission Interface — FAC-003-x, FAC-003-3 Successive Ballot
 - o Project 2007-09 — Generator Verification - MOD-025-2, MOD-027-1 and PRC-019-1 Initial Ballot
 - o Project 2010-07 — Generator Requirements at the Transmission Interface - PRC-005-1.1a Initial Ballot
 - o Project 2007-03 — Real-time Transmission Operations — TOP-001 through TOP-008 and PER-001 Successive Ballot
- Continue to monitor emerging issues such as High Impact Low Probability, Smart Grid, Renewable Resources, and CIP development.
- The NPCC RSC in conjunction with TFIST is actively reviewing and commenting on 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) and promoting understanding of the requirements and implementation of the proposed standards.
- 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-
<https://www.npcc.org/Standards/Regional%20Standards%20Comments/Forms/Public%20List.aspx>

- o Project 2010-05 Interpretation of CIP-002-1 Requirement R3 for Duke Energy
 - o Project 2009-26 Interpretation of CIP-004-1 for the Western Electricity Coordinating Council
 - o Project 2011-INT-02 - Interpretation of VAR-002 for Constellation
 - o Project 2006-06 Reliability Coordination, COM-1, COM-2, and IRO-001
 - o Order 754 - Request for Data or Information
 - o Project 2010-17 Phase 2 - Definition of BES (SAR)
- 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 feasibility of Eastern Interconnection standards and scheduling of NERC's resources to evaluate regional standards and coordinating standards requirements as well as investigating website standardization of regional standards information.
- 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.



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

Date: May 1, 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 approved at the March 1, 2012 RCC meeting:

- ✓ November 29, 2011 RCC Meeting Minutes
- ✓ Roster Changes
- ✓ Task Force Roster Changes
- ✓ 2011 New York Interim Transmission Review
- ✓ Updated SS-38 Working Group Scope
- ✓ 2011 NPCC Long Range Adequacy Overview
- ✓ 2011 NPCC Special Protection System List, Major Projects List, Bulk Power System List, and Double-Circuit Tower Exclusions List
- ✓ Modification of the Bruce Type I Special Protection System (SPS)
- ✓ SS-38 Working Group Load Modeling White Paper Terms of Reference and Study Schedule
- ✓ Approval of NPCC Directory No. 6 – Reserve Sharing Groups– for NPCC Membership ballot

The IESO informed the RCC that two new 500 kV circuits (B501M and B502M) from the Bruce nuclear complex to the Milton SS will be included in the Bruce Type I SPS. With the commissioning of these new circuits it is anticipated that the Bruce SPS will be armed only during transmission outages, depending on system conditions.

Given that the in-service date of these new circuits has been advanced from late 2012 to spring 2012, the IESO is planning to present this modification to the Task Force on Coordination of Operation on March 27th, the Task Force on System Studies on March 29th, and the Task force on Coordination of Planning on April 17th. This change has already been reviewed and approved by the Task Force on System Protection. Assuming the other Task Force approvals, the IESO will be seeking RCC approval of the SPS modification at a conference call meeting scheduled for March 30th.

The Media Event releasing the 2012 NPCC Summer Reliability Assessment has been scheduled for May 3rd at 11:00 am. A summary of the assessment will be provided at the May 1st Board meeting.



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COMMITTEE MEMBERSHIP CHANGES

Reliability Coordinating Committee (RCC)

Sector (3) – Transmission Dependent Utilities (“TDUs”), Distribution Companies and Load, -Serving Utilities (“LSE”)

Mr. Michael Lupo as New York Power Authority member, replacing Ms. Marilyn Brown.

Sector (4) – Generator Owners

Ms. Connie Lowe as Dominion Resources Services, Inc. alternate, replacing Mr. Michael Gildea.

Compliance Committee (CC)

Sector (4) – Generator Owners

Ms. Connie Lowe as Dominion Resources Services, Inc. alternate, replacing Mr. Michael Gildea.

Regional Standards Committee (RSC)

Sector (4) – Generator Owners

Ms. Silva Parada Mitchell as Nextera Energy, LLC member, replacing Mr. Chantel Haswell.

Mr. Brian Murphy will no longer be the alternate member for Nextera Energy, LLC.

From: [Maritza Feliciano](#)
To: [npcc-bod-2012](#)
Cc: [grpStaff](#)
Subject: Agenda Package for the BOD Teleconference Meeting on May 1, 2012
Date: Tuesday, April 17, 2012 2:11:21 PM
Attachments: [Agenda Package for NPCC BOD Teleconference Meeting 5-1-12.pdf](#)
[Proxy Form for NPCC BOD Teleconference Meeting of 5-1-12.doc](#)
Importance: High



NPCC Board of Directors

This email is being provided on behalf of NPCC's President and CEO, Edward A. Schwerdt and serves as notice of an NPCC Board of Directors Teleconference Meeting to be held on Tuesday, May 1, 2012 from 10:00 a.m. until 1:00 p.m.

Attached are an initial agenda package and a form of proxy for the May 1, 2012 meeting. Additional agenda materials will be distributed next week as they become available. The NPCC Agenda Package for the Board of Directors Meeting has also 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 this meeting is:

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.

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📠 (212) 302-2782

mfeliciano@npcc.org



NORTHEAST POWER COORDINATING COUNCIL, INC.
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BOARD OF DIRECTORS **REVISED** AGENDA

Tuesday, May 1, 2012

10:00 a.m. – 1:00 p.m.

Meeting via Teleconference

Dial-In: 877-260-3999

Code: 6945#

-
1. Introductions/Quorum/Antitrust Compliance Guidelines	10:00
2. President's Report	10:05
3. Report by the Treasurer	10:15
a) Finance and Audit Committee Activities	
b) Annual Independent Audit of Financial Statements	
4. Consideration of draft NPCC Board of Directors Minutes	10:25
a) March 13, 2012 Teleconference Meeting	<i>[Action Required]</i>
5. Membership and Committee Changes	10:30
a) NPCC Membership Changes	
b) Committee Reports and Corporate Goals Scorecard (written reports only)	
c) RSC, CC, RCC, PIC Membership	<i>[Action Required]</i>
6. Administrative Matters	10:40
a) ~~2012 Management Salary Bandwidths~~ <i>Deferred</i>	~~<i>[Action Required]</i>~~
7. Summer 2012 Reliability Assessment	10:50
a) Operating Security Analyses and Probabilistic Assessment <i>(to be distributed following Task Force on Coordination of Planning approval)</i>	
8. NERC Member Representatives Committee and Board of Trustees	11:30
– May 8-9, 2012 <i>Agenda to be distributed by NERC at the end of April)</i>	
a) Preliminary NERC 2013 Business Plan and Budget	
b) NPCC BOD Policy Input	<i>[Action Required]</i>
9. Organizational Matters	12:15
a) Preliminary 2013 NPCC Budget <i>(to be distributed with NERC materials)</i>	
10. 2012 Board of Director Meeting Dates	12:30
• Tuesday, June 26, 2012 – NPCC Offices (10 a.m. – 5 p.m.)	
• Tuesday, August 7, 2012 – Teleconference (10 a.m. – 1 p.m.)	
• Wednesday, September 19, 2012 – NPCC Offices (10 a.m. – 5 p.m.)	
• Tuesday, October 30, 2012 – Teleconference (10 a.m. – 1 p.m.)	
• Wednesday, November 28, 2012 – Montreal, Québec (7:30 a.m. – 10 a.m.)	

Regional Approval Timelines

Region	Process	Notification Timing	Internal Posting	Action	Exception	Enforcement Date*
IESO	OEB Remand Ontario Electricity Act of 1998 Sect. 36.2 http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm#BK91	IESO receives notification from NERC or NPCC (criteria) and must post on the IESO website within 7 days of this notification.	IESO posts Standard or Criteria on its website.	Market Participants (including the IESO) have 21 days to apply to the OEB for a review of the Standard or Criteria.	OEB able to initiate review up to 120 days after notification	After 120 days if there is no request to review, Standard or Criteria is adopted as part of the Ontario Market Rules effective upon date of FERC/NPCC approval. If there is a request to review, the OEB would determine if the Standard (Criteria) unjustly discriminates and if so would remand back to the Standard or Criteria authority.
New Brunswick	Market Procedure #8 Section 4.3 http://www.nbsso.ca/public/_private/MP-08_Version4.pdf	NBSO initiates the New Brunswick adoption process upon receiving notification of Standard or Criteria approval, by the NERC Board of Trustees or NPCC Full Members.	NBSO reviews the content and implementation plan for a Reliability Standard and develops a schedule to adopt the Reliability Standard (Criteria) as an amendment to MP -8.	Interested parties may apply to the NB Energy & Utilities Board (EUB) for a formal review. An application made to the EUB for review does not stay the coming into effect of the Standard or Criteria on the adoption date unless otherwise directed by the EUB. The EUB has the authority to revoke the adoption and remand it back to NBSO for further consideration.	NBSO determines that the Standard or Criteria is urgent and files with the EUB to adopt in less than 30 days.	The NBSO will post the Standard and the proposed adoption and effective dates on the NBSO Website for a 30 day review before the reliability Standard comes into effect.

*The date on which the standard becomes mandatory and enforceable in accordance with the existing laws of the jurisdiction and the approval granted by the regulatory authority.

Regional Approval Timelines

Region	Process	Notification Timing	Internal Posting	Action	Exception	Enforcement Date*
Nova Scotia	MOU between Nova Scotia Power Inc.(NSPI) NPCC and NERC (May 9, 2010) http://www.nerc.com/files/NSUARB_NERC-NPCC-Order_20110720.pdf	NERC shall concurrently notify NSPI and the Nova Scotia Utility and Review Board (NSUARB) of Reliability Standards adopted by NERC. NPCC shall concurrently notify NSPI and the NSUARB Regional Criteria (Directories) adopted by NPCC.	N/A.	The NSUARB will direct NSPI to review and provide comments on Standards and Criteria. In response the NSPI will recommend either to: 1)Approve 2)Request Additional Information 3)Remand NSPI will propose a timeline for the NSUARB approval of the Standard and Criteria.		The UARB will not take any action on approving or remanding until such time as FERC has approved the Standard. Upon approval by the NSUARB NERC Reliability Standards and NPCC Criteria will become mandatory in Nova Scotia.
Quebec	Hydro Quebec acts as Quebec's Reliability Coordinator (Coordinator). http://www.hydroquebec.com/transenergie/fiabilite/pdf/r-3699_2009_en.pdf		The Reliability Coordinator submits Standards to the Regie for adoption.		The Regie set the date for Implementation of PRC 018-1 (DM) at six years to allow entities time to install necessary facilities. The Régie dismisses the Coordinator's proposal to make compliance with NPCC criteria mandatory by mere reference to the reliability standards adopted by the Régie.	Reliability Standards mandatory 60 days after adoption by the Regis.
United States						FERC approved reliability standards become mandatory and enforceable in the United States on a date established by the orders approving the standards.

*The date on which the standard becomes mandatory and enforceable in accordance with the existing laws of the jurisdiction and the approval granted by the regulatory authority.

From: [Guy V. Zito](#)
To: [grpStaff](#)
Subject: Fwd: [uflsdt] [mro-all] MRO HOT TOPICS: MRO is Moving - April 26-27, 2012
Date: Tuesday, April 24, 2012 7:40:10 PM

For those who may not know, see below.

Guy

Sent from my iPhone

Begin forwarded message:

From: "Jessica R. Mitchell" <JR.Mitchell@MidwestReliability.org>
To: "Jessica R. Mitchell" <JR.Mitchell@MidwestReliability.org>
Subject: [uflsdt] [mro-all] MRO HOT TOPICS: MRO is Moving - April 26-27, 2012

<image007.png>

April 24, 2012 Target Audience: All MRO Members and Stakeholders	ANNOUNCEMENT: Midwest Reliability Organization is Moving! Midwest Reliability Organization (MRO) Members and Stakeholders: Please note that MRO will be moving on Thursday, April 26 and Friday, April 27, 2012, to the Lawson Commons in downtown St. Paul, Minnesota. During this time, please use email for primary communication. Our website and EFT server will also be up and available. For immediate assistance during our move, please contact one of the following individuals.
Topics Check the MRO Calendar to Learn About Upcoming Meetings and Conferences in the MRO Region Check the MRO Website	

for Newsletters
Containing Tips and
Lessons Learned

Contact

Midwest Reliability
Organization

2774 Cleveland Ave N

Roseville, MN 55113

Ph. 651-855-1760

Fx. 651-855-1712

www.midwestreliability.org

Compliance:	Russ Mountjoy	Cell: 651-366-1246
Enforcement:	Sara Patrick	Cell: 612-483-0177
Mitigation:	Riaz Islam	Cell: 952-393-7668
(Ops & Planning)		
Mitigation:	Richard Burt	Cell: 651-346-8394
(CIP)		
Standards:	Will Smith	Cell: 917-526-2371
Events:	Dan Schoenecker	Cell: 651-500-0625
Other:	Dan Skaar	Cell: 651-260-4948

Or, dial the MRO Emergency line at: 651-734-8355.

MRO will permanently occupy its new space on Monday, April 30, 2012.
Kindly update your records with our new address:

Midwest Reliability Organization

380 St. Peter Street, Suite 800

St. Paul, MN 55102

Our phone numbers and email addresses will remain the same.

Thank you.

If you no longer wish to receive MRO e-notices, please [unsubscribe](#)

You are currently subscribed to uflsdt as: gzito@npcc.org.

To unsubscribe click here: <http://listman.midwestreliability.org/u?id=2789.b19aa25ff58940d974234b48391b9549&n=T&l=uflsdt&o=93678>

(It may be necessary to cut and paste the above URL if the line is broken)

or send a blank email to leave-93678-2789.b19aa25ff58940d974234b48391b9549@midwestreliability.org

	Recommendation	Regional or Continent-wide	Responsible Entities	Related Standards	Requirement or Best Practice	Sufficient Tech Details Exist	ERCOT Draft Comments
1	Balancing Authorities, Reliability Coordinators, Transmission Operators and Generation Owner/Operators in ERCOT and in the southwest regions of WECC should consider preparation for the winter season as critical as preparation for the summer peak season. (page 205)	NA	NA	NA	Best practice	No	NERC Standards don't differentiate criticality for seasonal preparedness, but for all times and especially during emergencies. Any winterization requirements should be as addressed below.
2	Planning authorities should augment their winter assessments with sensitivity studies incorporating the 2011 event to ensure there are sufficient generation and reserves in the operational time horizon. (page 206)	Continent-wide	BA	TOP-002-2b.	Existing Requirement	NA	There is already a requirement to ensure there are plans that are designed to operate reliably through a reasonable future time period in TOP-002-2b. To go beyond this and planning for greater than an N-1, N-2 event is beyond the standards. Standards should not be developed for addressing resource adequacy, such as 'sufficient generation' for a Planning Authority.
3	Balancing Authorities and Reserve Sharing Groups should review the distribution of reserves to ensure that they are useable and deliverable during contingencies. (page 206)	Continent-wide	BA	BAL-002-R1, TOP-002-2b R7.	Existing Requirement	NA	This requirement is already covered in BAL-002-0 R1 and TOP-002-2b R7.
4	ERCOT should reconsider its protocol that requires it to approve outages if requested more than eight days before the outage,	Continent-wide	GOP	IRO-004-2 R1.	Requirement	Yes	An RC already has authority consistent with IRO-001-2 R3, R8, and IRO-004-2 R1, but GOP could be added to IRO-004-2 R1 applicability for operations planning time horizon. NERC should

	consider giving itself the authority to cancel outages previously scheduled, and expand its outage evaluation criteria. (page 206)						recognize that coordination typically takes place to meet TOP-003-1 R4 between resources and the RC to see if there is even a possibility of cancelling an outage before a directive is or is not issued. ERCOT Region has revised the ERCOT Protocols to clarify this recommendation from FERC - NPRR365 was passed, approved by the ERCOT Board of Directors, giving ERCOT ISO the ability to withdraw approval for previously approved or accepted resource outages (ERCOT Protocol sections 3.1.3.8 through 3.1.6.9).
5	ERCOT should consider modifying its procedures to (i) allow it to significantly raise the 2300 MW responsive reserve requirement in extreme low temperatures, (ii) allow it to direct generating units to utilize preoperational warming prior to anticipated severe cold weather, and (iii) allow it to verify with each generating unit its preparedness for severe cold weather, including operating limits, potential fuel needs and fuel switching abilities. (page 207)	Continent-wide	BA	EOP-002-3 R4, TOP-002-2b R13 and R14.	Existing Requirement	NA	(i)ERCOT ISO already has procedures to raise responsive reserves when it deems necessary. (ii)EOP-002-3 R4 already addresses it to bring on all available generation. (iii) This is addressed in TOP-002-2b R13 and R14. Any winterization requirements should be as addressed below. Consideration should be to give GOP's a requirement to follow a directive from a BA. ERCOT believes the region has addressed the FERC recommendations.
	COORDINATION WITH GENERATOR OWNERS/OPERATORS (5)						
6	Transmission Operators, Balancing Authorities, and Generation Owner/Operators should consider developing mechanisms to verify	Continent-wide	BA	TOP-002-2b R13.	Revise Requirement	Yes	Tweak TOP-002-2b R13 accordingly.

	that units that have fuel switching capabilities can periodically demonstrate those capabilities. (page 208)						
7	Balancing Authorities, Transmission Operators and Generator Owners/Operators should take the steps necessary to ensure that black start units can be utilized during adverse weather and emergency conditions. (page 209)	NA	NA	NA	NA	NA	Any winterization requirements should be as addressed below.
8	Balancing Authorities, Reliability Coordinators and Transmission Operators should require Generator Owner/Operators to provide accurate ambient temperature design specifications. Balancing Authorities, Reliability Coordinators and Transmission Operators should verify that temperature design limit information is kept current and should use this information to determine whether individual generating units will be available during extreme weather events. (page 209)	Continent-wide	BA, TOP and GOP	TOP-002-2b R15.	Existing Requirement	Yes	Revise requirement to at least, for winter and summer, specifically request temperature design limits to be incorporated into its operational planning analysis. However, a BA cannot determine when a unit will trip, regardless of the limits that are reported in a planning or operations horizon. A BA can anticipate increased risk at various temperatures and consider appropriately adjusting reserves, communications, emergency plans etc. accordingly. This may help increase BA, TOP and GOP situational awareness.
9	Transmission Operators and Balancing Authorities should obtain from Generator Owner/Operators their forecasts of real output capability in advance of an anticipated severe weather event; the forecasts should take into	Continent-wide	GOP	TOP-002-2b R15.	Revise Requirement	Yes	Revise requirement TOP-002-2b R15 for additional specific detail as to what the forecasts should consider and what should be included in the forecast.

	account both the temperature beyond which the availability of the generating unit cannot be assumed, and the potential for natural gas curtailments. (page 210)						
10	Balancing Authorities should plan ahead so that emergency enforcement discretion regarding emission limitations can be quickly implemented in the event of severe capacity shortages. (page 210)	Continent-wide	BA	EOP-002-3 R6.	Revise Requirement	Yes	Pull out from EOP-001 and spell out clearly in EOP-002-3 R6 as one of the parts.
	WINTERIZATION (10)						
11	States in the Southwest and southwest should examine whether Generator/Operators ought to be required to submit winterization plans, and should consider enacting legislation where necessary and appropriate. (page 211)	Continent-wide	BA	EOP-001-0b	Revise Requirements	Yes	Consider adding requirements for GOPs to implement weatherization plans annually prior to a predetermined date by the entity. When notified of upcoming severe weather, review and implement short term weatherization actions prior to the severe weather arrival. Consider identifying elements of consideration for weatherization plans (items 14 – 19 below). Weatherization (which includes winterization) plans should be submitted to the CEA and CEA's should audit those plans and implementation of those plans, not the BA.
12	Consideration should be given to designing all new generating plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient						You should not exclude generation from entering market place because it cannot operate at some temperature level, this would hinder development, being aware of risk and incorporating into analysis is the value. This can be encouraged and I am sure is encourage when

	temperature for the nearest city for which historical weather data is available, factoring in accelerated heat loss due to wind speed. (page 212)						specifying new generation after such a build, because high load periods are higher price periods.
13	The temperature design parameters of existing generating units should be assessed. (page 212)	NA	NA	NA	Best practice	No	This is not an exact science and would not be worth the effort.
14	Generator Owner/Operators should ensure that adequate maintenance and inspection of its freeze protection elements be conducted on a timely and repetitive basis. (page 213)						See item 11.
15	Each Generator Owner/Operator should inspect and maintain its generating units' heat tracing equipment. (page 214)						See item 11.
16	Each Generator Owner/Operator should inspect and maintain its units' thermal insulation. (page 215)						See item 11.
17	Each Generator Owner/Operator should plan on the erection of adequate wind breaks and enclosures, where needed. (page 215)						See item 11.
18	Each Generator Owner/Operator should develop and annually conduct winter-specific and plant-specific operator awareness and maintenance training. (page 216)						See item 11.
19	Each Generator Owner/Operator						See item 11.

	should take steps to ensure that winterization supplies and equipment are in place before the winter season, that adequate staffing is in place for cold weather events, and that preventative action in anticipation of such events is taken in a timely manner. (page 216)						
20	Transmission Operators should ensure that transmission facilities are capable of performing during cold weather conditions. (page 217)	NA	NA	NA	Best practice	No	What does “performing”, what are “cold weather” conditions.
	COMMUNICATIONS (4)						
21	Balancing Authorities should improve communications during extreme cold weather events with Transmission Owner/Operators, Distribution Providers, and other market participants. (page 218)	NA	NA	NA	Best practice	No	
22	ERCOT should review and modify its Protocols as needed to give Transmission Service Providers and Distribution Service Providers in Texas access to information about loads on their systems that could be curtailed by ERCOT as Load Resources or as Emergency Interruptible Load Service. (page 218)						
23	WECC should review its Reliability Coordinator procedures for providing notice to Transmission						WECC can comment but is already addressed in the standards.

	Operators and Balancing Authorities when another Transmission Operator or Balancing Authority within WECC is experiencing a system emergency (or likely will experience a system emergency), and consider whether modification of those procedures is needed to expedite the notice process. (page 219)						
24	All Transmission Operators and Balancing Authorities should examine their emergency communications protocols or procedures to ensure that not too much responsibility is placed on a single system operator or on other key personnel during an emergency, and should consider developing single points of contact (persons who are not otherwise responsible for emergency operations) for communications during an emergency or likely emergency. (page 219)	NA	NA	NA	Best practice	No	Several best practices, communication to other entities than those involved with operating actions is important but not as important as those that have to take immediate actions during the emergency.
LOAD SHEDDING (2)							
25	Transmission Operators and Distribution Providers should conduct critical load review for gas production and transmission facilities, and determine the level of protection such facilities should be accorded in the event of system stress or load shedding. (page 219)	Continent-wide	TOP	EOP-001-0b	Revise Requirements	Yes	Delineate which attachment items in EOP-001-0b are only BA obligations and which are only TOP obligations (in line with the Functional Model), and which are both. Add additional detail to item 13 to include gas production and transmission facilities.

							The Attachment also includes many 'should' statements which can create confusion strictly from a compliance point of view. These need to be reviewed and either removed since they could be considered Best Practice, or included in the Standards as Requirements (shall statements)
26	Transmission Operators should train operators in proper load shedding procedures and conduct periodic drills to maintain their load shedding skills. (page 220)	Continent-wide	RC, BA, TOP	PER-005-1 R3.	Existing Requirement	NA	R3 already addresses.

Cold Weather Review Participants

Mike Gentry - Salt River Project, mike.gentry@srpnet.com

Dave Hawkins - El Paso Electric, dave.hawkins@epelectric.com

Tim Ponsetti – TVA, teponseti@tva.gov

Ken McIntyre – ERCOT, kmcintyre@ercot.com

Michelle D'Antuono- Oxy, Michelle_DAntuono@oxy.com

Brenda Hampton - Luminant, Brenda.Hampton@luminant.com

From: [Guy V. Zito](#)
To: [tfco-all](#)
Cc: [rsc](#)
Subject: FW: Cold Weather scoping participant from the north
Date: Tuesday, April 24, 2012 8:21:49 PM
Attachments: [Cold Weather Analysis ERCOT Draft.docx](#)
[Cold Weather Review Participants List 4-24-2012.docx](#)

TFCO and RSC,

As a result of the cold snap in Texas last year that froze up some of their plants, NERC is launching a study of potential improvements to standards and promulgating lessons learned. They have asked NPCC to participate and help advise the group with any best practices related to cold weather protection and review their proceedings. Let me know if your organization is able to help with this effort. I don't think it will be very time consuming, a few teleconferences.

Thanks for your consideration.

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: Herb Schrayshuen [Herb.Schrayshuen@nerc.net]
Sent: Tuesday, April 24, 2012 4:55 PM
To: david.kiguel@HydroOne.com; Guy V. Zito
Subject: Cold Weather scoping participant from the north

David, Guy

I have a number of volunteers and am ready to get started with a first organizational call. Did you find someone to participate?

Herb Schrayshuen
Vice President Standards and Training
Mobile: 315 439 1390
Office: 404 446 2563
herb.schrayshuen@nerc.net

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Atlanta, GA 30326

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NORTHEAST POWER COORDINATING COUNCIL, INC.
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Northeast Power Coordinating Council, Inc. (NPCC)

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- 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;
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Reliability Coordinating Committee

April 30, 2012

Agenda

Teleconference

1:00 p.m. to 2:00 p.m.
Dial-In Number: (719) 785-1714
Code: 8093

- 1.0 Introductions/Quorum/Antitrust Compliance Guidelines**
- 2.0 RCC Chair Report**
 - 2.1 Agenda
- 3.0 Items for Approval [Action Required]**
 - 3.1 Modification of the Bruce Type I Special Protection System
 - 3.2 NPCC Reliability Assessment for Summer 2012
- 4.0 Other Matters**



**Northeast
Utilities System**

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Northeast Utilities Service Company
P.O. Box 270
Hartford, CT. 06141-0270
(860) 665-6500

**Bradley P. Bentley - Director
Transmission System Planning
Phone: (860) 665-6371
Fax: (860) 665-2609**

*RCC Meeting
April 30, 2012
Agenda Item 3.1*

April 18, 2012

Mr. Don Gates, Chair - Reliability Coordinating Committee (RCC)
Members, Reliability Coordinating Committee

Re: Modification to the Bruce Type I Special Protection System (SPS) #112 – additional functionality due to the new 500 kV circuits B501M and B502M.

The IESO is requesting RCC approval of the enhancements to the Bruce Type I SPS due to the anticipated completion of the two new 500 kV circuits - B501M and B502M, between the Bruce nuclear complex and the Milton S/S. With the commissioning of these new circuits in the spring of 2012, it is anticipated that the Bruce SPS will need to be armed only to manage transmission outages, depending on system conditions. The attached technical document outlines the IESO modification to this SPS and the operating conditions that will be included in its functionality.

The modification of this SPS was reviewed and accepted by:

- TFSP (re – approval letter dated February 3, 2012),
- TFSS (re – approval letter dated April 4, 2012), and by
- TFCO (re – approval letter dated April 9, 2012).

TFCP was provided with a presentation by the IESO which outlined the latest modifications to this SPS at a teleconference/WebEX on April 17, 2012. TFCP concurs with the findings of the other task force groups that these recent enhancements of the Bruce SPS continue to classify it as a Type I SPS, and submits them to the RCC with a recommendation for approval at your April 30, 2012 meeting.

Cordially yours,

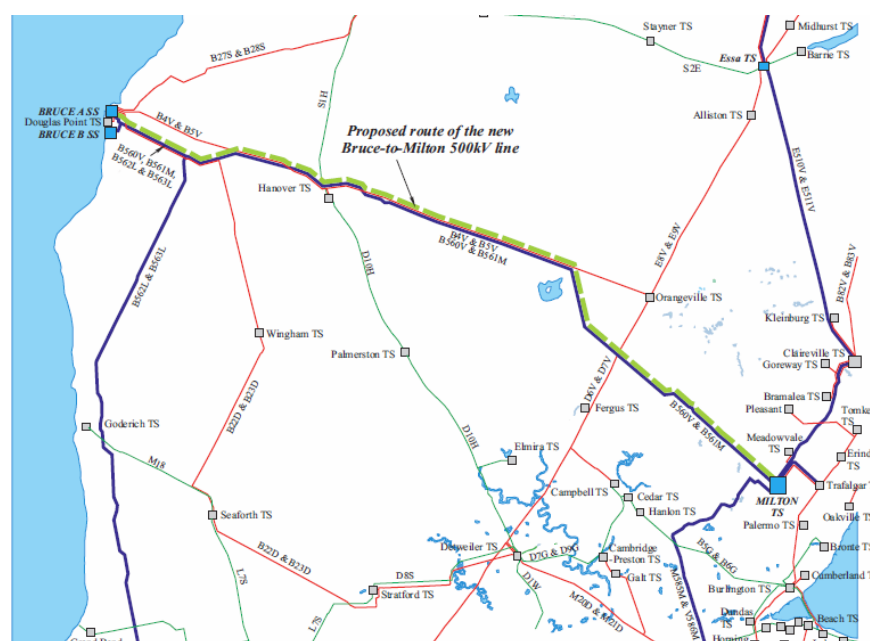
Bradley P. Bentley
Director, Transmission System Planning
Chairman, TFCP

Attachment:

IESO "Request for Type I Classification – Addition of new 500 kV circuits B501M and B502M to Bruce SPS (dated March 19, 2012)

cc: TFCO, Task Force on Coordination of Operation
TFSS, Task Force on System Studies
TFSP, Task Force on System Protection
TFCP, Task Force on Coordination of Planning

The Ontario Independent Electricity System Operator (IESO) has recently been informed that the in-service date of the two new 500 kV circuits B501M and B502M, between the Bruce nuclear complex and the Milton SS has been advanced from late 2012 to spring 2012. These circuits are about 180 km, with the general location shown in figure 1 below.



Monitoring of the new contingencies related to these new 500 kV circuits will be added to the functionality of the Bruce SPS, and given the desired advanced service date, IESO is requesting TFCO, TFSS and TFCP to review this submission at the upcoming TFCO meeting in March 27, TFSS meeting in March 29, and TFCP conference call in April 17.

With the commissioning of the new Bruce to Milton 500 kV circuits B501M and B502M, the Bruce SPS will be used only to manage outage conditions in the transmission system, to ensure that the power system can continue to be operated reliably with up to 8 generating units in-service at the Bruce Complex, together with all committed wind turbine generating facilities installed in the area.

This functionality will be used to improve the transfer limit out of the Bruce area on the FABCW interface, during outage conditions. This transfer limit is an IROL (Interconnection Reliability Operating Limit) and, therefore if the SPS failed to operate there could be unacceptable adverse impact outside of local area. Given this fact and the fact that the existing Bruce SPS is already classified as a Type I SPS, the IESO proposes to classify the Bruce SPS with this enhancement as a Type I SPS.

3. System Conditions and Bruce SPS Actions studied in this submission

The system conditions studied are summarized below:

- IESO Load: 26850 MW
- Bruce 8 units: 6880 MW
- Wind output: 1740 MW
- IESO Gen: 27965 MW
- Darlington 4 units: 3720 MW
- FIT Projects: 3800 MW
- Import/Export: 0 MW
- Pickering 2 units: 1084 MW
- Nanticoke: 0 MW
- BLIP: -1500 MW
- FABCW: 6690 MW
- Lambton 1 unit: 290 MW

The BLIP (Buchanan Longwood Input) and FABCW (Flow Away from Bruce Complex + Wind) are major power system interfaces used in the formulation of operating limits in SW Ontario. The Bruce SPS actions studied in this submission include rejecting one Bruce generating unit, tripping of 4 shunt reactors at Longwood TS and tripping of 3 shunt reactors at Bruce TS, initiated by a tower contingency causing the loss of the two new 500 kV circuits B501M and B502M. The following sections describe the performance of the power system for proper operation, misoperation, and failure to operate of the Bruce SPS.

4. Bruce SPS armed and operated correctly

Table 1 shows the voltage at selected buses for the pre and post B501M + B502M contingency conditions in different scenarios assuming that the BSPS was armed and correctly operated for the contingency. The BSPS was armed for the 3 Bruce reactors, 4 Longwood reactors and 1 Bruce unit. The voltages and their deviations are within the IESO criteria. Therefore, there would not be any adverse impact on the power system due to the new enhancements to the BSPS.

Table 1 –Voltage at Selected Buses for the Loss of B501M and B502M with proper BSPS Operation

Monitored Bus	All I/S			B561M O/S			B560V O/S		
	Pre-contingency kV	Post-contingency kV	Deviation %	Pre-contingency kV	Post-contingency kV	Deviation %	Pre-contingency kV	Post-contingency kV	Deviation %
Bruce A 500 kV	542	542	0.1%	541	541	0.0%	542	543	0.2%
Bruce B 500 kV	543	543	0.0%	543	543	0.0%	543	543	0.0%
Milton 500 kV	525	515	-1.8%	519	502	-3.3%	519	503	-3.1%
Claireville 500 kV	522	515	-1.4%	518	502	-3.0%	517	505	-2.3%
Longwood 500 kV	537	541	0.6%	534	528	-1.2%	534	532	-0.4%
Nanticoke 500 kV	537	530	-1.3%	530	513	-3.4%	531	516	-2.7%
Middleport 500 kV	537	530	-1.3%	531	514	-3.3%	530	516	-2.5%
Bruce A 230 kV	243	249	2.3%	244	248	1.8%	244	249	2.2%
Longwood 230 kV	240	243	1.6%	238	238	0.0%	238	240	0.7%
Detweiler 230 kV	244	244	0.0%	244	243	-0.6%	244	244	0.0%
Middleport 230 kV	244	241	-1.3%	245	238	-2.9%	245	239	-2.3%
Claireville 230 kV	244	241	-1.2%	242	236	-2.6%	242	237	-2.1%

The pre and post-contingency power flows in the main 500 kV circuits with all elements in service are shown in figures 3 and 4 below. To facilitate the comparison of results, all ratings shown are continuous ratings.

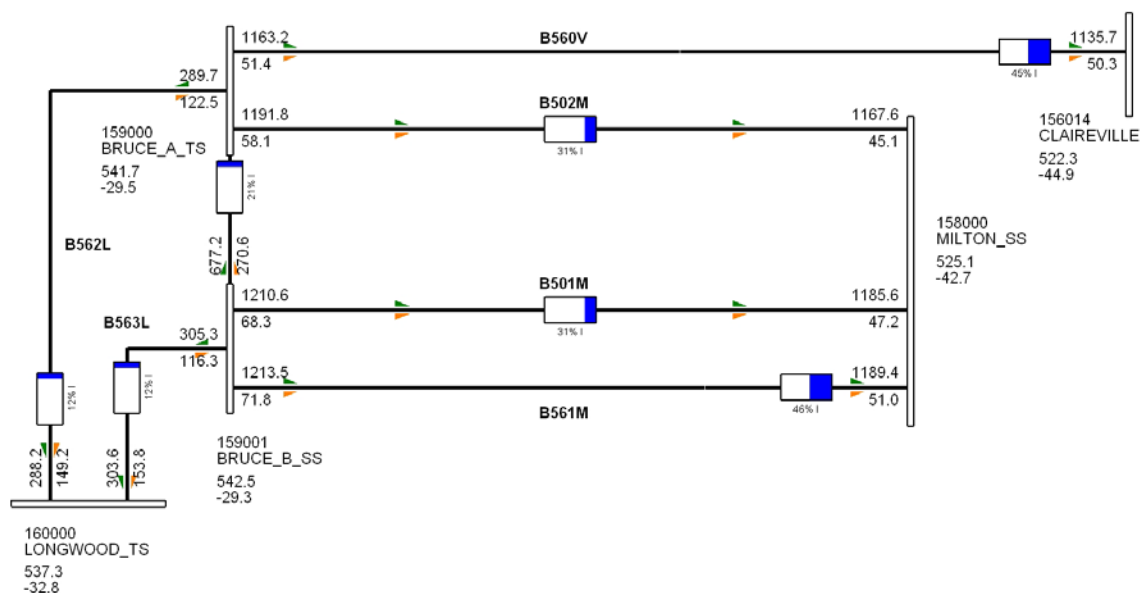


Figure 3 – Pre-contingency flows and loadings in main 500 kV circuits with all elements in service

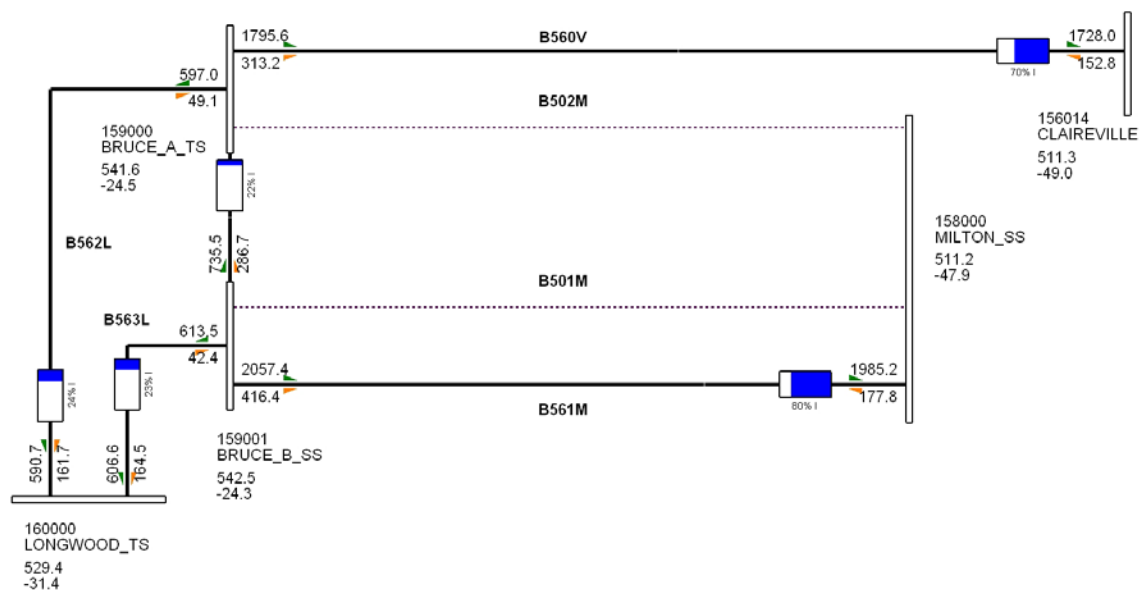


Figure 4 – Post-contingency flows and loadings after loss of B501M+B502M with all elements in service and no SPS operation

The pre and post-contingency power flows in the main 500 kV circuits with B560V out of service are shown in the figures 5 and 6 below. To facilitate the comparison of results, all ratings shown are continuous ratings.

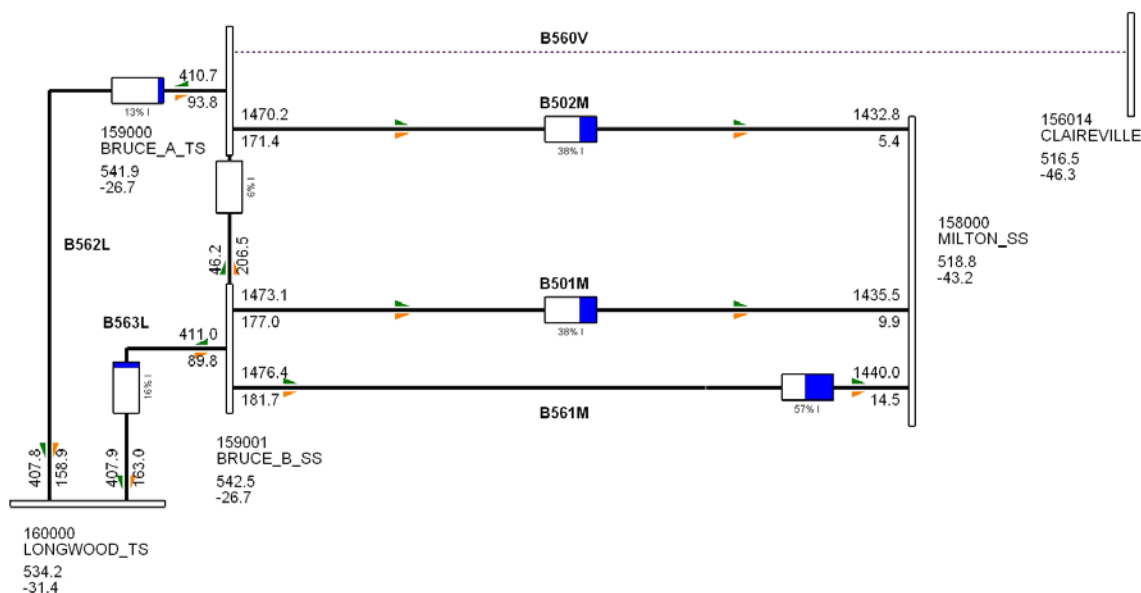


Figure 5 – Pre-contingency flows and loadings in main 500 kV circuits with B560V out of service

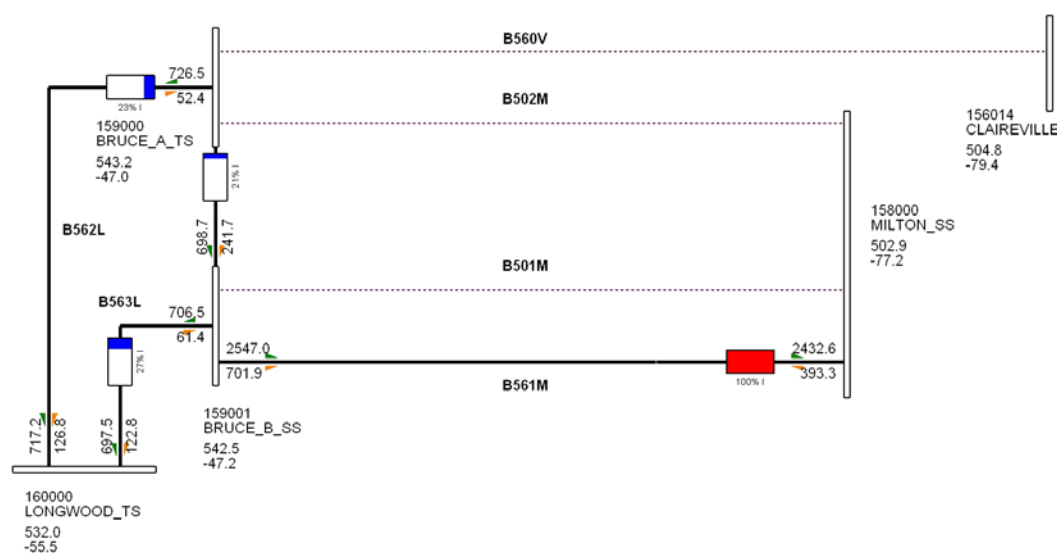


Figure 6 – Post-contingency flows and loadings after loss of B501M+B502M with B560V out of service and proper SPS operation

5. Bruce SPS armed and failed to operate

Table 2 shows the voltage at the selected buses for the pre and post B501M + B502M contingency conditions in different scenarios assuming that the BSPS was armed for the contingency but failed to operate. It can be seen that the post-contingency simulations diverged only for the outage scenarios, but not with all elements in service. These results indicate that the BSPS is not required with all elements in service.

The results also show that the BSPS is only required for the outage conditions and its failure to operate may result in voltage collapse in the Bruce area and the loss of significant amounts of generation. This could have

a significant adverse effect outside of the local area and, therefore, the enhanced Bruce SPS with the addition of the new 500 kV circuits continues to be classified as Type I. Please refer to section 8 for additional details.

Table 2 – Voltages at Selected Buses for the Loss of B501M and B502M with SPS Failure to Operate

Monitored Bus	All I/S			B561M O/S			B560V O/S		
	Pre-contingency kV	Post-contingency kV	Deviation %	Pre-contingency kV	Post-contingency kV	Deviation %	Pre-contingency kV	Post-contingency kV	Deviation %
Bruce A 500 kV	542	542	0.0%	541	Diverged	-	542	Diverged	-
Bruce B 500 kV	543	543	0.0%	543	Diverged	-	543	Diverged	-
Milton 500 kV	525	511	-2.7%	519	Diverged	-	519	Diverged	-
Claireville 500 kV	522	511	-2.1%	518	Diverged	-	517	Diverged	-
Longwood 500 kV	537	529	-1.5%	534	Diverged	-	534	Diverged	-
Nanticoke 500 kV	537	525	-2.3%	530	Diverged	-	531	Diverged	-
Middleport 500 kV	537	526	-2.1%	531	Diverged	-	530	Diverged	-
Bruce A 230 kV	243	244	0.4%	244	Diverged	-	244	Diverged	-
Longwood 230 kV	240	236	-1.3%	238	Diverged	-	238	Diverged	-
Detweiler 230 kV	244	244	0.0%	244	Diverged	-	244	Diverged	-
Middleport 230 kV	244	240	-1.8%	245	Diverged	-	245	Diverged	-
Claireville 230 kV	244	240	-1.8%	242	Diverged	-	242	Diverged	-

6. Bruce SPS armed and misoperated

If the Bruce SPS misoperates, the actions described in section 3 (rejection of a generating unit plus tripping of shunt reactors) would occur without an initiating contingency. The results of the simulations indicate that the voltages at bulk power system stations in Southern Ontario would be within acceptable ranges. Table 3 below shows the voltages at selected buses confirming that the misoperation of the B501M and B502M will not have an adverse impact on the power system.

Table 3 – Voltages at Selected Buses with SPS Misoperation without any Contingency

Monitored Bus	All I/S			B561M O/S			B560V O/S		
	Pre-contingency kV	Post-contingency kV	Deviation %	Pre-contingency kV	Post-contingency kV	Deviation %	Pre-contingency kV	Post-contingency kV	Deviation %
Bruce A 500 kV	542	542	0.1%	541	542	0.1%	542	543	0.1%
Bruce B 500 kV	543	543	0.0%	543	543	0.0%	543	543	0.0%
Milton 500 kV	525	527	0.4%	519	522	0.5%	519	522	0.6%
Claireville 500 kV	522	524	0.4%	518	520	0.4%	517	519	0.5%
Longwood 500 kV	537	547	1.7%	534	544	1.8%	534	544	1.8%
Nanticoke 500 kV	537	540	0.6%	530	534	0.7%	531	534	0.7%
Middleport 500 kV	537	540	0.5%	531	534	0.6%	530	533	0.6%
Bruce A 230 kV	243	248	1.9%	244	248	1.9%	244	249	1.9%
Longwood 230 kV	240	246	2.5%	238	244	2.6%	238	245	2.6%
Detweiler 230 kV	244	246	0.6%	244	245	0.5%	244	246	0.7%
Middleport 230 kV	244	245	0.3%	245	246	0.3%	245	246	0.3%
Claireville 230 kV	244	245	0.3%	242	243	0.3%	242	243	0.3%

7. Transient Stability Simulations

The IESO has identified that the prevalent limiting phenomena in southern Ontario is voltage collapse. Transient stability is limiting only during very infrequent operating conditions, depending on outages of transmission elements. The results of transient stability simulations are shown in the figures below.

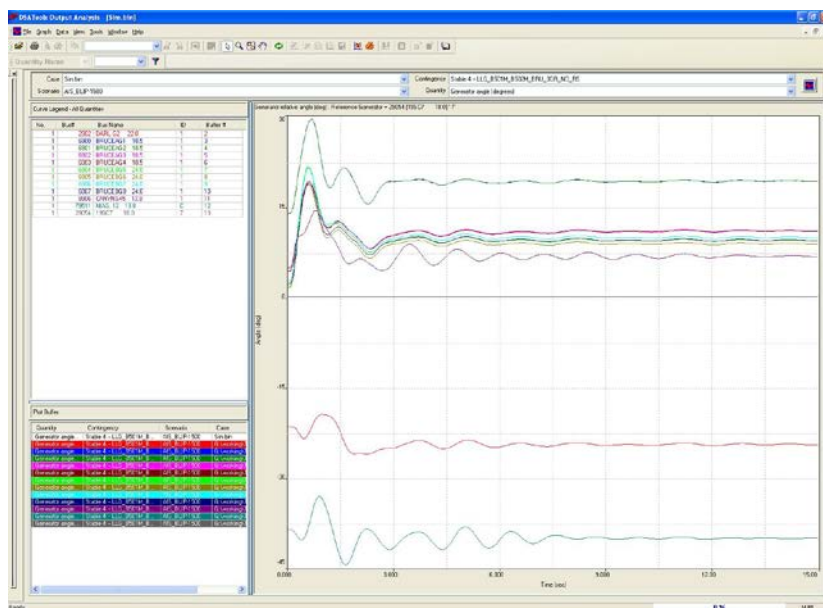


Figure 7 – Rotor angles after loss of B501M + B502M, all elements in service, no SPS operation

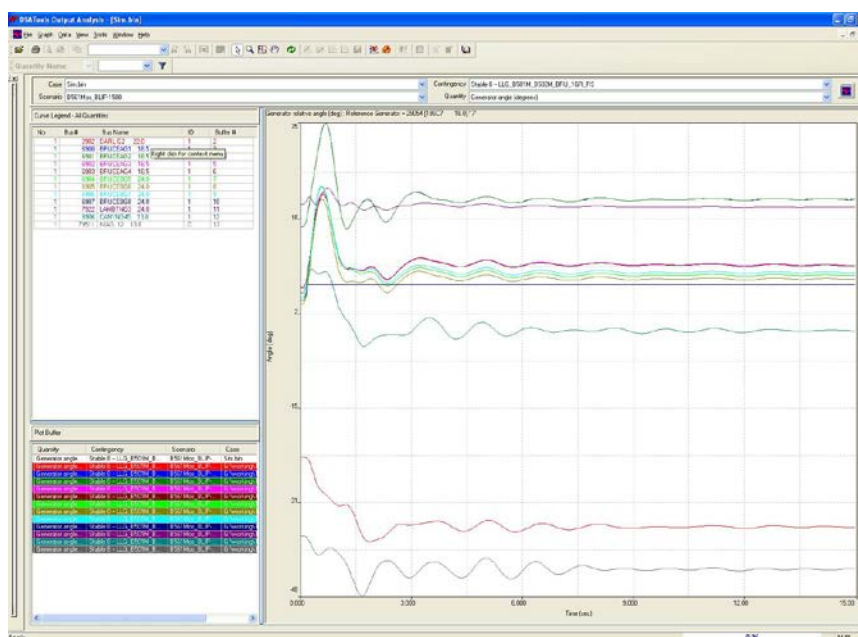


Figure 8 – Rotor angles after loss of B501M + B502M, B561M out of service and proper SPS operation

It can be seen that the oscillations in the generator rotor angles are well damped and the power system shows stable behaviour.

8. Voltage Stability Study

The IESO performed additional voltage stability studies in order to further investigate the collapse point for the B560V out of service condition with the B501M+B502M contingency when the SPS fails to operate. To do so, instead of rejecting a whole unit at Bruce, the studies simulated running back one Bruce unit from the full capacity to zero in a step of 50 MW. In this process the results revealed that for the conditions studied running back the unit does not have any impact on the voltage collapse, and that failure to trip the shunt reactors at Longwood and Bruce would be the main cause for the voltage collapse.

The figures below show the voltage profiles at various buses in the Ontario power system, following SPS action that trips various combinations of shunt reactors: 0, 1, 2 or 3 shunt reactors tripped at Bruce, and 0, 1, 2, 3, 4 or 5 reactors tripped at Longwood.

The simulations show that voltage collapse is avoided by tripping at least one shunt reactor at Bruce, or by tripping at least 2 shunt reactors at Longwood.

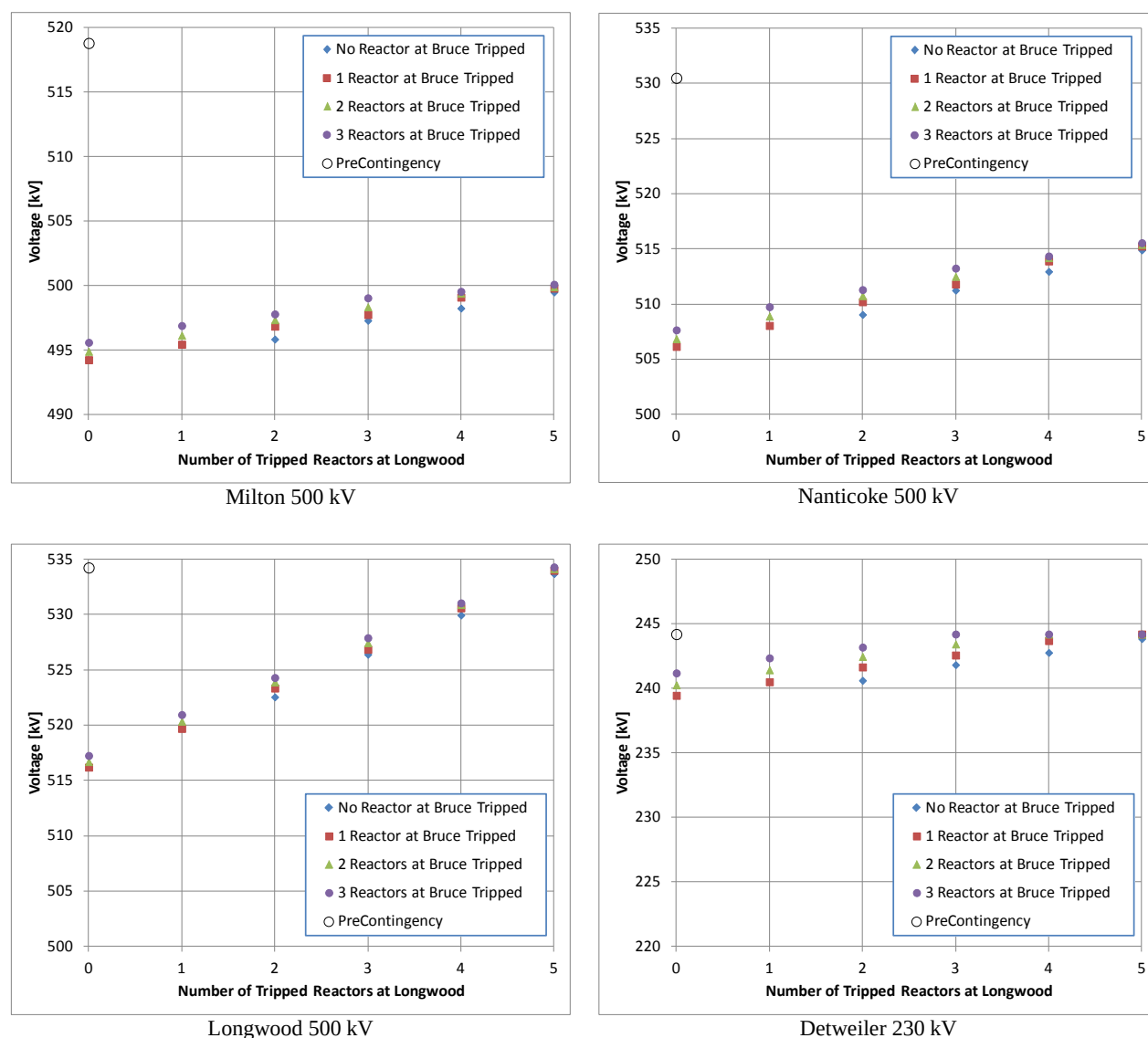


Figure 9 – Voltages after tripping shunt reactors with proper SPS operation

Additional studies were performed with the SPS tripping one reactor at Longwood and running back Bruce G8. For this particular action the simulations show that with B560V out of service, reducing the output of G8 by as little as 100 MW following the B501M+B502M contingency would maintain healthy system voltages.

The graphs in Figure 10 below illustrate the PV curve for selected 500 kV and 230 kV buses.

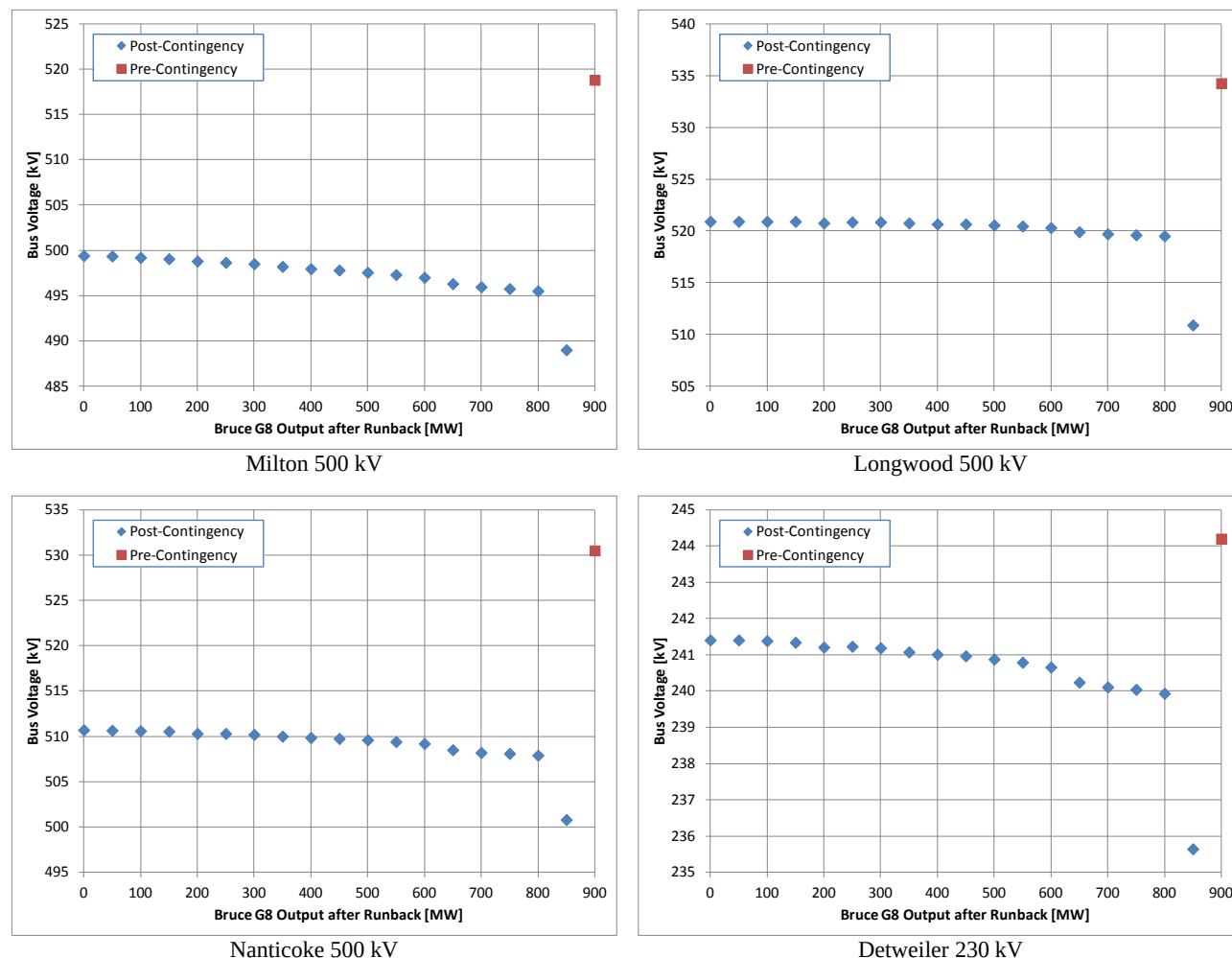


Figure 10 – PV curves for selected buses

The Bruce SPS offers the ability to arm 3 shunt reactors at Bruce and 5 shunt reactors at Longwood, allowing to maintain a very large safety margin in the reliability of the power system with, without arming generation, for the operating conditions that are prevalent most of the time.

In addition, with the commissioning of the two new 500 kV circuits Bruce to Milton, the Bruce SPS will be used only during outage conditions, further reducing the need to arm generation rejection.

9. Conclusions

The conclusions of this study are as follows:

1. With proper operation of the modified Bruce SPS, the post-contingency voltages and element loadings will not exceed applicable ratings.

2. If the modified Bruce SPS misoperates, the post-contingency voltages and element loadings will not exceed applicable ratings.
3. If the modified Bruce SPS fails to operate, the consequences could lead to voltage collapse in the Bruce area and the loss of significant amounts of generation. This could have a significant adverse effect outside of the local area, therefore the modified Bruce SPS continues to be classified as Type I.

Based on the conclusions presented above, the IESO is requesting the Task Forces on Coordination of Planning (TFCP), Coordination of Operation (TFCO) and System Studies (TFSS) to classify the modified Bruce SPS with the addition of new 500 kV circuits B501M and B502M as a Type I SPS, as defined in the NPCC Regional Reliability Reference Directory #7, Special Protection System.

The new circuits were part of the material recently reviewed and approved by TFSP, which already communicated its approval to TFCP. After the review by the task forces is complete, the IESO will seek RCC approval for the inclusion of the new 500 kV circuits in the Bruce SPS.

With the commissioning of the new circuits, the Bruce SPS will be used only to manage outage conditions in the transmission system.

- End of Document -

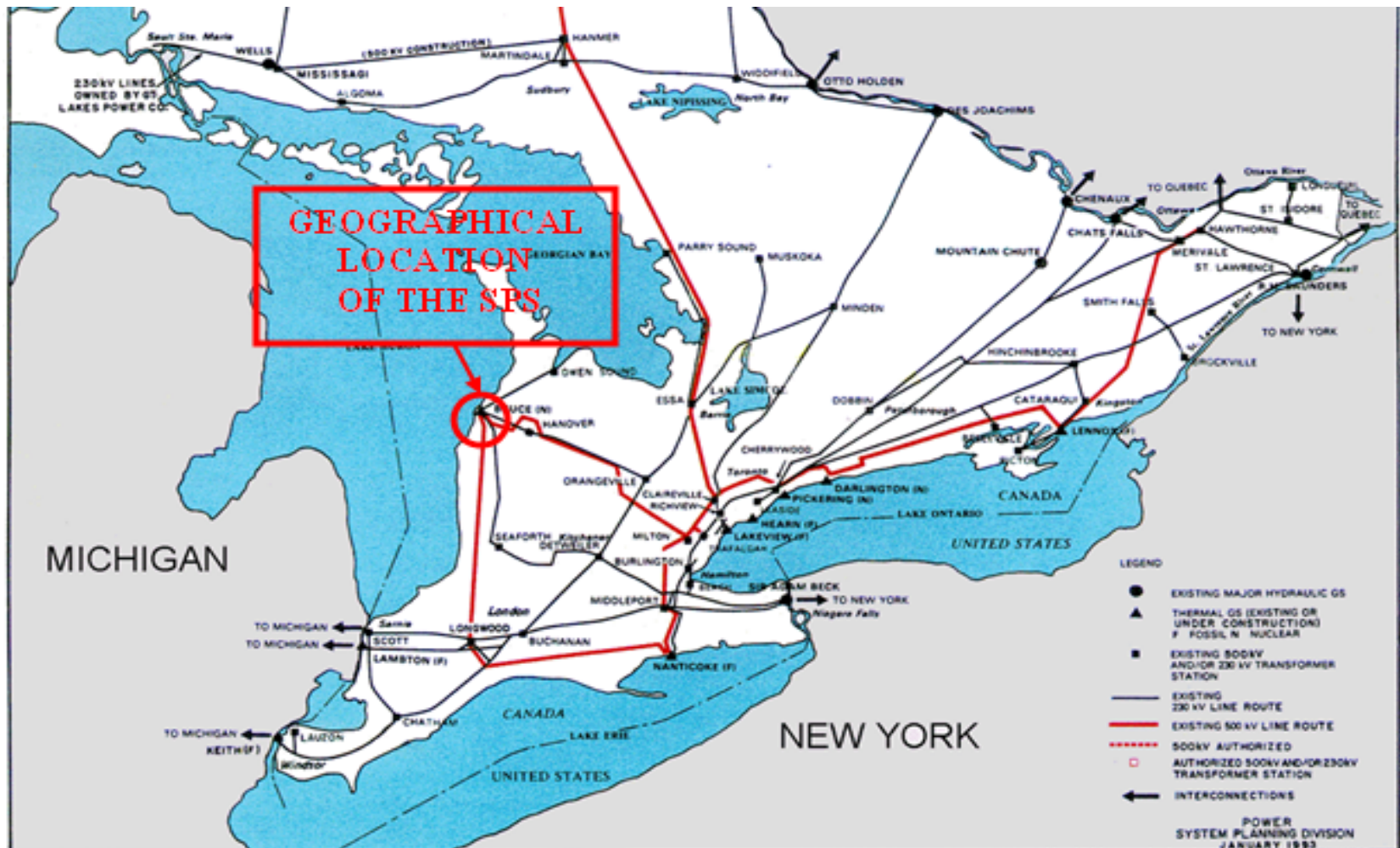
NPCC Classification of Enhanced Bruce SPS with new 500 kV lines Bruce-Milton

Presentation to RCC – April 30, 2012



- Enhancements to Bruce SPS, required to accommodate the return to service of the remaining two Bruce generating units, and to allow arming of wind farms in the Bruce area for rejection in response to contingency conditions:
 1. Monitoring of additional contingencies at 500 and 230 kV;
 2. Cross tripping of 115 kV circuit S2S;
 3. Reactivation of idle load rejection selections;
 4. Tripping of wind farm facilities, and
 5. Ramp up of SVCs at Nanticoke and Detweiler.
- On March 1, 2012 RCC approved these enhancements
- Today's presentation:
 - Addition to Bruce SPS of the two new 500 kV circuits B501M and B502M between Bruce and Milton;
 - Review of this addition by NPCC task forces is complete (TFSP Jan 24, TFCO March 27, TFSS March 29, TFCP April 17)
 - IESO is requesting RCC approval of the classification of this addition to the Bruce SPS as type I.

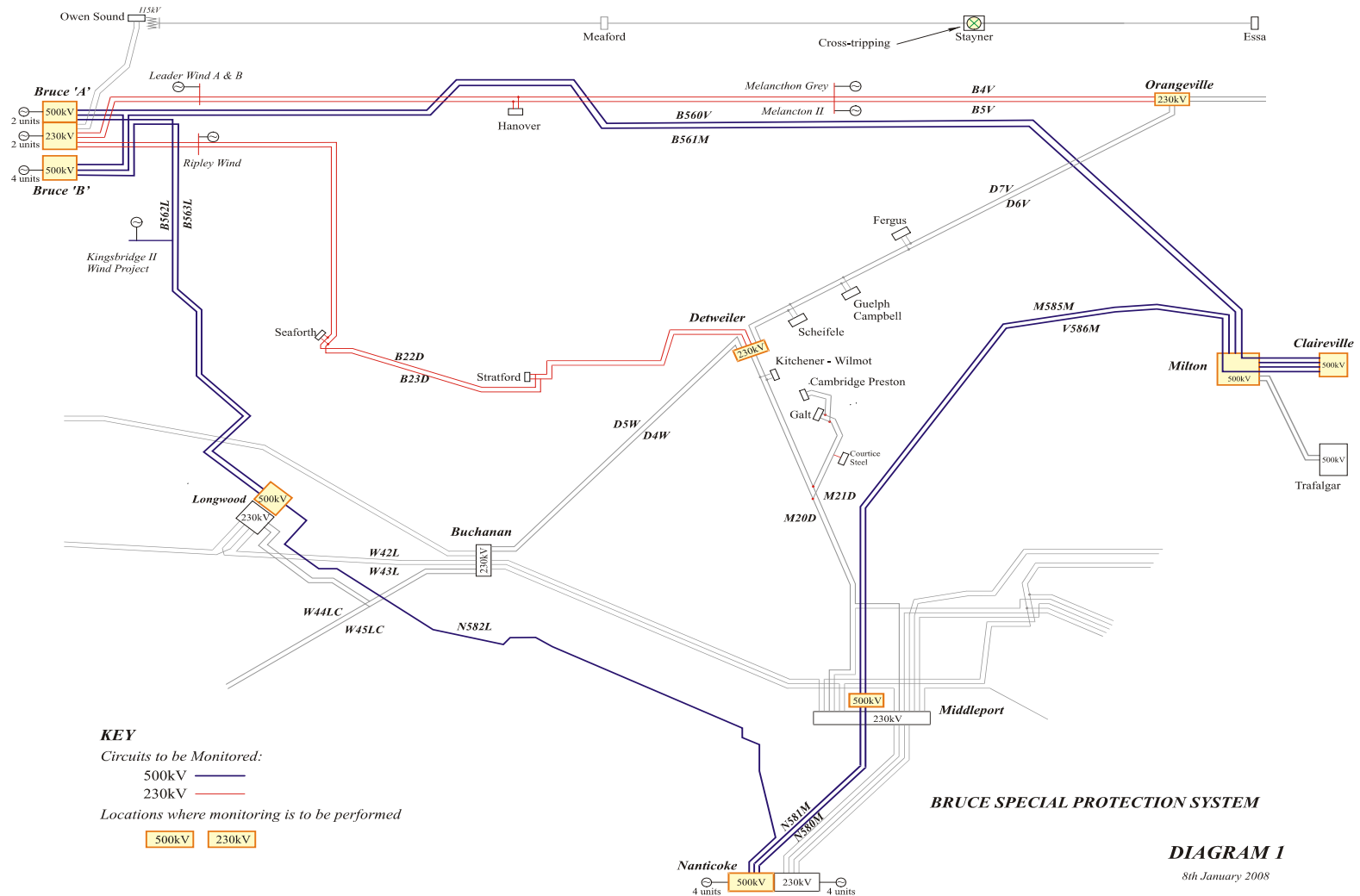
Location of the Bruce SPS



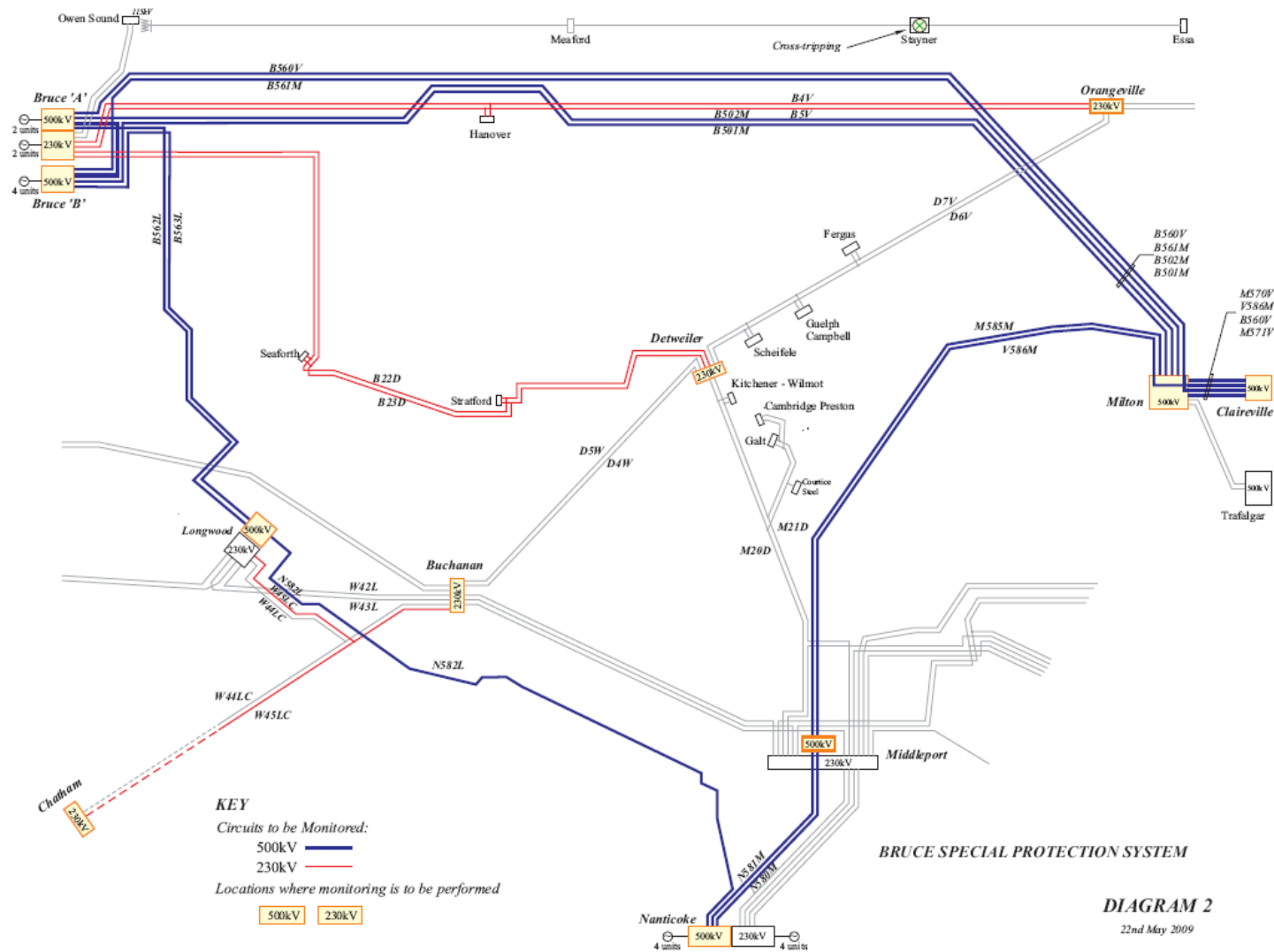
Addition of new 500 kV circuits Bruce-Milton to the Bruce SPS

- The Bruce SPS generation rejection functionality is presently being armed about 30 % of the time, depending on outages to elements of the transmission system, the number of Bruce units in service, and the output from the wind generation facilities in the region.
- Hydro One is finalizing construction of the new 180 km, two-circuit 500 kV line Bruce-Milton, which will remove the need for arming this SPS with all transmission facilities in service.
- The in-service date of the two new 500 kV circuits Bruce-Milton has been advanced from late 2012 to spring 2012.
- Addition of the new 500 kV circuits to Bruce SPS already reviewed and approved by TFSP, TFCO, TFSS and TFCP.
- IESO is seeking RCC approval of this change to the Bruce SPS.

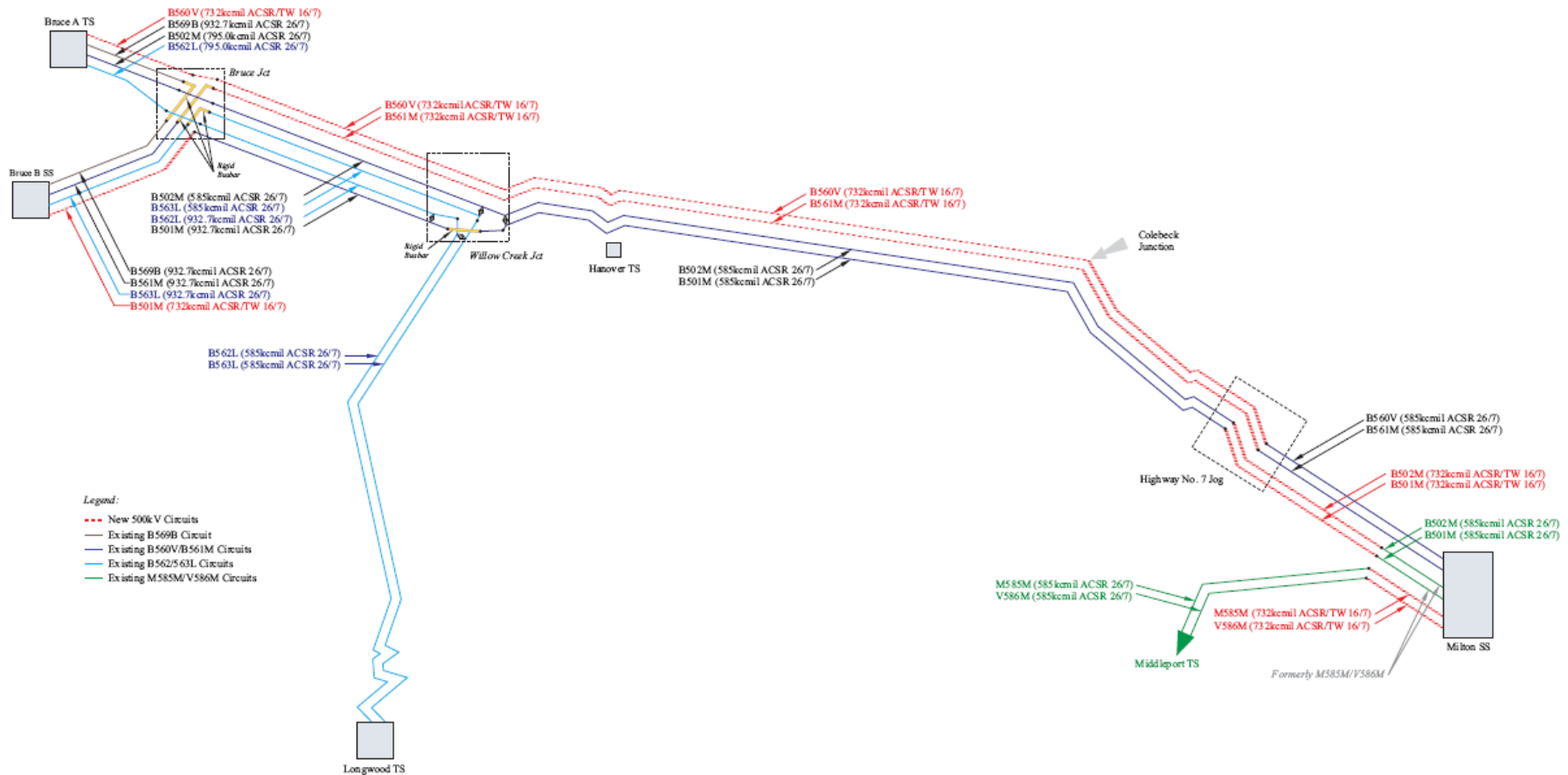
Present Ontario Transmission System Monitored by the Enhanced Bruce SPS



Future Transmission System to be Monitored by the Enhanced Bruce SPS



Connectivity of the new 500 kV circuits B501M & B502M Bruce-Milton



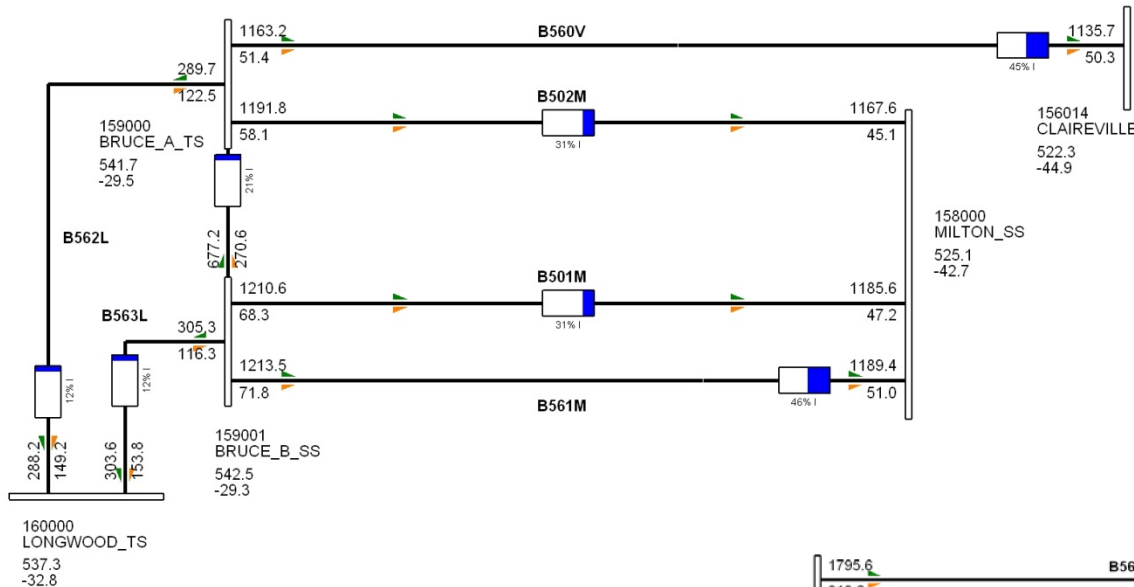
Proposed Location of the New 500kV Circuits within the Transmission Corridors in the Bruce Area

DIAGRAM 3

12th January 2010

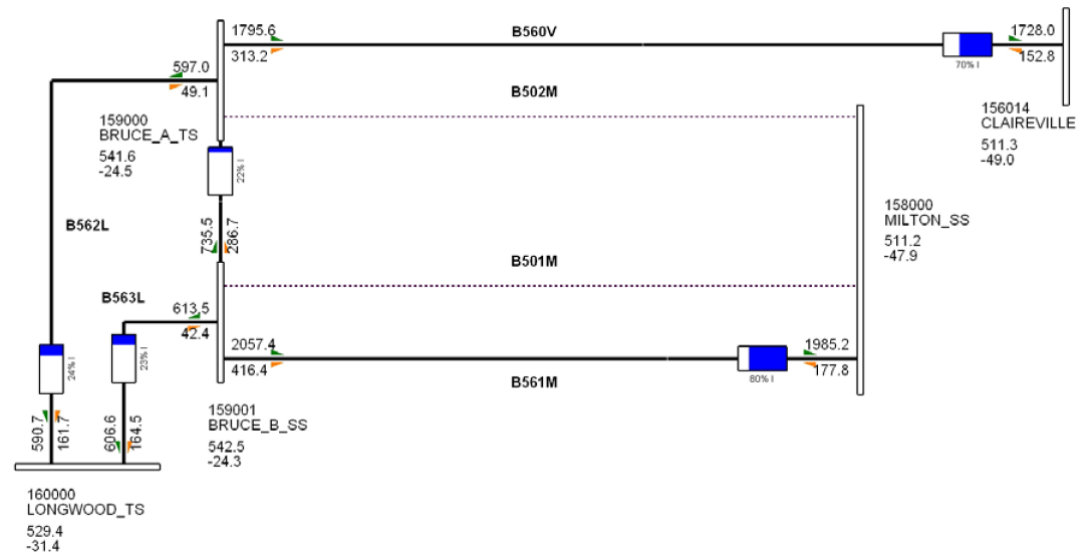
- New contingencies to be monitored by Bruce SPS:
 - Loss of B501M and B502M
 - Loss of B501M and B563L
 - Loss of B501M and B562L
 - Loss of B502M and B563L
 - Loss of B501M
 - Loss of B502M
- Studied the loss of B501M+B502M with all elements in service (no SPS required), and with B561M or B560V out of service (1 unit rejected at Bruce, plus shunt reactor tripping at Longwood and Bruce)

Load Flow Simulations with all elements in service

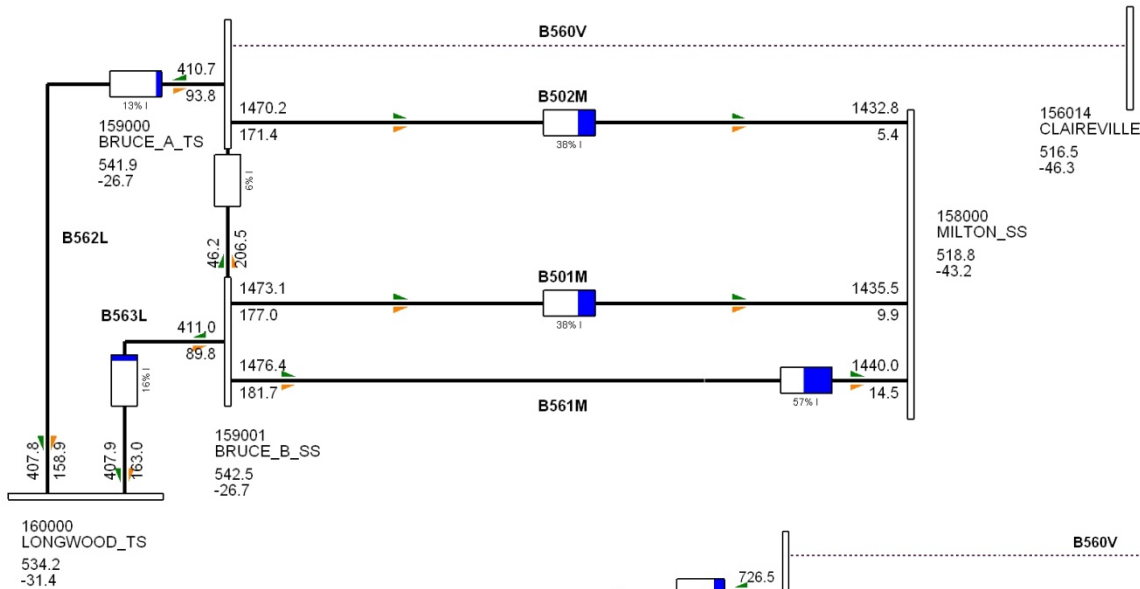


Bruce output on 500 kV
lines pre-contingency:
about 5300 MW

Bruce output on 500 kV
lines after loss of B501M
and B502M: about 5000
MW (no SPS action
required)

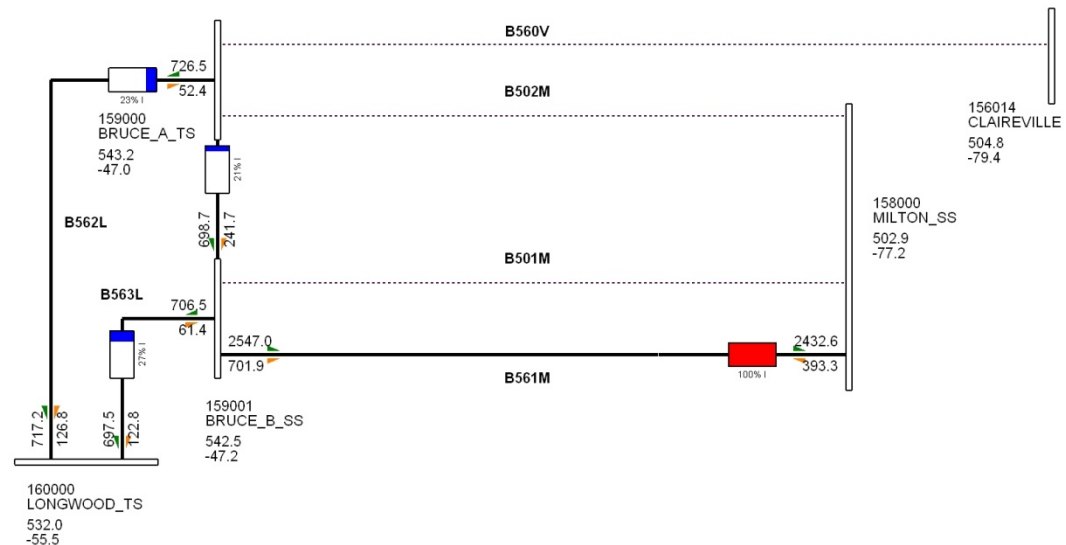


Load Flow Simulations with B560V out of service



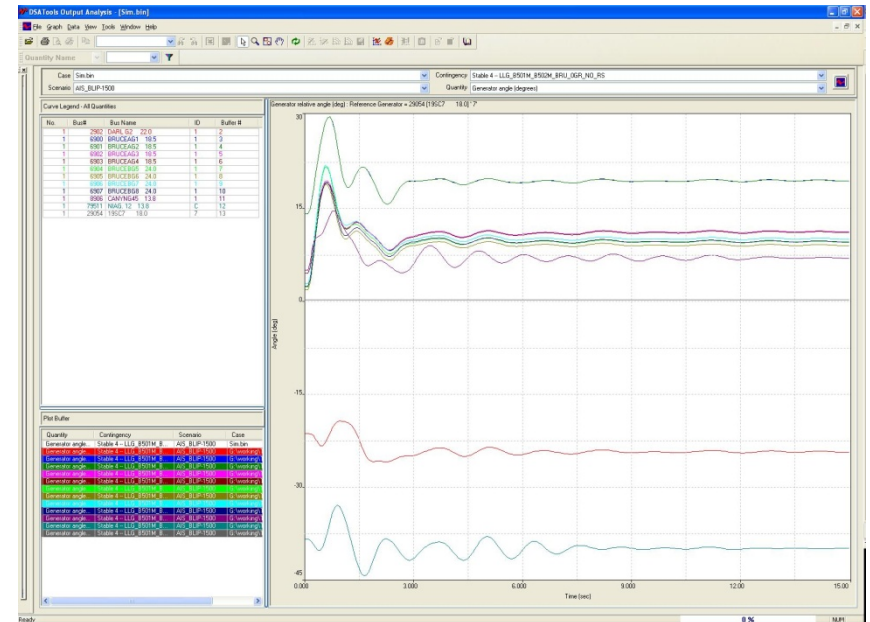
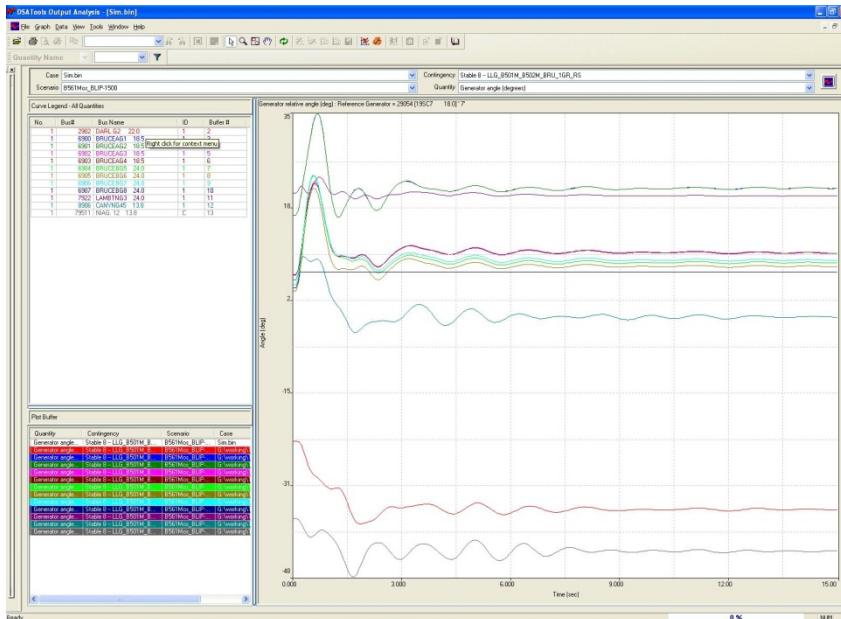
Bruce output in 500 kV
lines pre-contingency:
about 5300 MW

Bruce output in 500 kV
lines after loss of B501M
and B502M : about 4000
MW (with SPS action).
All figures show
continuous ratings



Transient Stability Simulations with all in service and B561M out of service

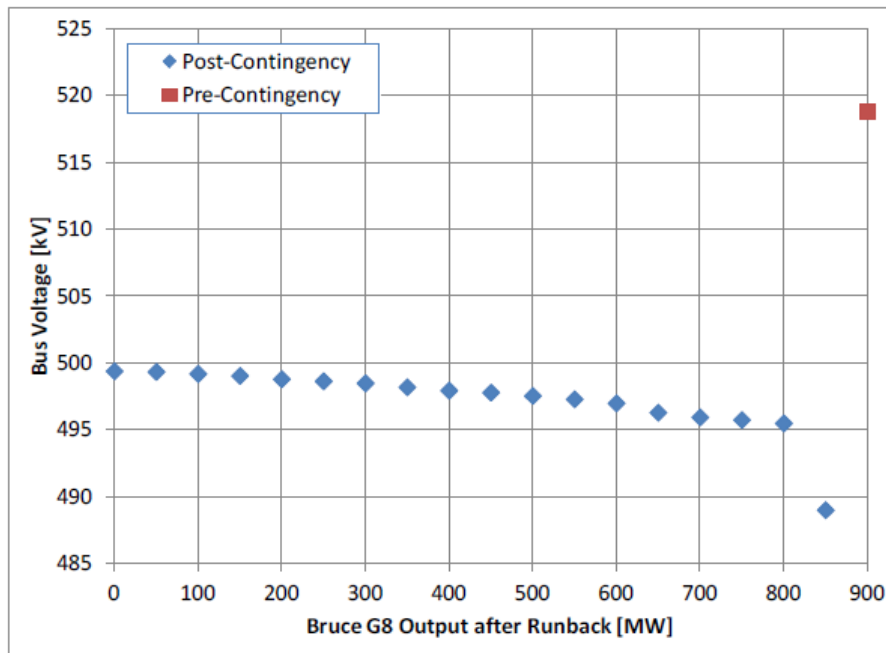
Generator rotor angles after
loss of B501M + B502M
with all elements in service,
and no SPS operation



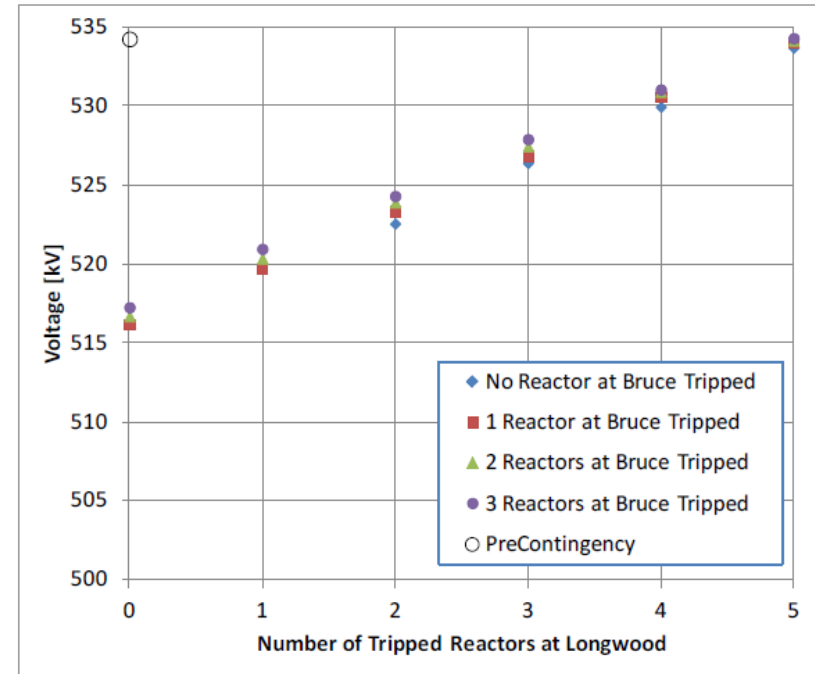
Generator rotor angles after
loss of B501M + B502M with
B561M out of service and
proper SPS operation

Voltage Stability Simulations with B560V out of service

Tripping of 1 shunt reactor at Bruce, or 2 at Longwood is sufficient to keep healthy voltages post-contingency; no G/R required for most operating conditions



Milton 500 kV



Longwood 500 kV

Sample PV curve obtained varying G8 output; 100 MW reduction is sufficient to move away from nose point

Review and classification of addition of B501M and B502M to Bruce SPS

- System studies performed by the IESO for the addition of B501M and B502M to the Bruce SPS show that the misoperation of the SPS would not have adverse inter-area or inter-regional effect, nor would it trigger operation of any other SPS. Failure to operate could cause significant adverse impact outside local area.
- The Bruce SPS with the new circuits B501M and B502M continues to be a Type I SPS in conformance with NPCC Directory 7 Special Protection Systems
- Addition of new 500 kV circuits B510M and B502M to Bruce SPS was already reviewed and approved by TFSP, TFCO, TFSS and TFCP.
- IESO is seeking RCC approval of the classification of this addition to the Bruce SPS as type I.
- With the commissioning of the two new 500 kV circuits between Bruce and Milton, the IESO anticipates that the Bruce SPS will be armed only during transmission outages, depending on system conditions.

- Contact:
barbara.constantinescu@ieso.ca
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- Thank you for your time!



NORTHEAST POWER COORDINATING COUNCIL, INC.
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April 26, 2012

Mr. Donald L. Gates

Chair

Mr. Alden Briggs

Co-Vice Chair

Mr. Michael Schiavone

Co-Vice Chair

Members, NPCC Reliability Coordinating Committee
and

Ms. Jennifer Budd Mattiello

Mr. Edward A. Schwerdt

Re: Approval of the Report of the NPCC Operations Planning Working Group (CO-12),
"Northeast Power Coordinating Council Reliability Assessment for Summer 2012"

Sir / Madam:

The NPCC Operations Planning Working Group (CO-12) conducts operational assessments of the reliability of the transmission system and the adequacy of available resources in the NPCC Region for the summer and winter operating periods. Attached please find the draft report submitted for your approval of the CO-12 assessment for the coming summer period, "Northeast Power Coordinating Council Reliability Assessment for Summer 2012."

The CO-12 Working Group believes that NPCC and the associated Reliability Coordinator areas have adequate generation and transmission for the summer operating period and have developed the necessary strategies and procedures to deal with operational problems and emergencies as they may develop. Key results and observations from the assessment include the following:

- The NPCC total projected summer peak demand is about 107,000 MW, which is about 1,400 MW lower than the comparable 2011 summer forecast; the NPCC net margin is about 3,000 MW more than that projected in the 2011 assessment.
- There is an increase in overall NPCC capacity. Contributing to this increase will be the return to service from refurbishment of two generating units in Ontario, Bruce G1 and Bruce G2.
- Enhancements to the 500 kV and 345 kV transmission systems are expected to be completed, including the addition of two Bruce-Milton 500 kV lines in Ontario

and the addition of the Gowanus 345 kV ring bus in New York. Additionally, operation of three of the four phase angle regulators on the Ontario-Michigan Interface is anticipated.

The CO-12 Working Group also coordinates its analysis with the seasonal probabilistic assessments conducted by the NPCC Working Group CP-08, "Working Group on Resource and Transmission Adequacy." The CP-08 multi-area probabilistic reliability assessment is provided in Appendix VIII of the Northeast Power Coordinating Council Reliability Assessment for Summer 2012."

Through a conference call held on April 23, 2012, the NPCC Task Force on Coordination of Operation approved the report, "Northeast Power Coordinating Council Reliability Assessment for Summer 2012," and recommends its approval by the NPCC Reliability Coordinating Committee

Very truly yours,

J. G. Mosier, Jr.

John G. Mosier, Jr.
Assistant Vice President of System
Operations

JGM:cd

cc: Members, Task Force on Coordination of Operation
Members, Task Force on Coordination of Planning
Members, Task Force on Infrastructure Security and Technology
Members, Task Force on System Protection
Members, Task Force on System Studies



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*RCC Meeting
April 30, 2012
Agenda Item 3.2*

April 26, 2012

Mr. Don Gates, Chair - Reliability Coordinating Committee (RCC)
Members, Reliability Coordinating Committee

Re: NPCC 2012 Summer Reliability Assessment report

TFCP has reviewed this report which indicates that the use of operating procedures designed to mitigate resource shortages (reducing 30-minute reserve, voltage reduction, and reducing 10-minute reserve) is not anticipated during the 2012 summer period under expected conditions. Slower economic growth than anticipated, coupled with the continuing impacts of conservation initiatives has resulted in a lower overall NPCC demand forecast compared to last year. Furthermore, new resources and transmission capacity resulting from transmission projects planned to be available by this summer are additional factors that act to minimize the expected need for the use of these operating procedures in 2012.

Operating procedures are available to maintain reliability for the unlikely simultaneous combination of severe system conditions (such as reductions in anticipated resources, delay of expected transmission projects and/or additional constraints) materializing coincident with higher than expected loads (such as caused by a wide spread, prolonged heat wave with high humidity and near record temperatures).

TFCP would like to thank the members of the CO-12 and CP-8 Working Groups, and the other supporting contributors for their efforts in the preparation of the report.

Both TFCO and TFCP have reviewed and approve this report.

TFCP submits the attached report to the RCC with a recommendation for its approval at your April 30, 2012 meeting.

Cordially yours,

Bradley P. Bentley
Director, Transmission System Planning
Chairman, TFCP

Attachment: NPCC 2012 Summer Reliability Assessment Report – dated April 2012

cc: TFCP, Task Force on Coordination of Planning
TFCO, Task Force on Coordination of Operation



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Northeast Power Coordinating Council Reliability Assessment For Summer 2012

**Draft Report for RCC Approval
April 30, 2012**

**Conducted by the
NPCC CO-12 & CP-8 Working Groups
April, 2012**

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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:

Yan Béchamp (Chair)	Independent Electricity System Operator
Rod Hicks	New Brunswick System Operator
John Medal	Independent Electricity System Operator
Paul Metsa	Hydro-Québec TransÉnergie
Dragan Pecurica	Nova Scotia Power
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Kyle Ardolino	New York Independent System Operator

Information for neighboring Reliability Councils provided by:

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
Frank Ciani	New York Independent System Operator
Kevan Jefferies	Ontario Power Generation
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Abdelhakim Sennoun	Hydro-Québec Distribution
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Vithy Vithyananthan	Independent Electricity System Operator
Fei Zeng	ISO New England

The CP-8 Working Group acknowledges the efforts of Messrs. Glenn Haringa, GE International, Inc, Patricio Rocha, the PJM Interconnection, and thanks them 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 2012 Summer Operating Period. Portions of this report are based on work previously completed for the NPCC Reliability Assessment Summer 2012.

Moreover, the NPCC CP-8 Working Group provides a seasonal multi-area probabilistic reliability assessment. Results of this assessment are included as Chapter 8 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 summer of 2012 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 Reliability Coordinator areas' ability to deal with the differing resource and transmission configurations within NPCC and the associated Reliability Coordinator 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 July 8, 2012)¹ is 107,052 MW. The capacity outlook indicates a forecasted Net Margin for that week of 19,576 MW. A total of 9,710 MW of the Net Margin is in the Québec and Maritimes Reliability Coordinator areas. The transfer capability between the Québec and Maritimes Reliability Coordinator areas to the remainder of NPCC will not permit the use of all this forecasted spare capacity. As a result, the spare capacity available to the remainder of NPCC after bottling during the peak week is reduced by 3,754 MW for a Revised Net Margin of 15,823 MW. (See Table AP-1 of Appendix I). Transfer Capability from Québec and the Maritimes is calculated from data obtained from Appendix III and Bottled Resources are calculated in Table AP-7 of Appendix I.

- The week with the forecasted minimum Net Margin after accounting for bottled resources (Revised Net Margin) occurs during the week beginning July 15, 2012. The minimum Revised Net Margin is 15,811 MW.
- The forecasted Installed Capacity during the week beginning July 8, 2012 in the NPCC region is 2,317 MW greater than it was for the corresponding NPCC peak week in summer 2011. When the new capacity, rerates and retirement

¹ Load and Capacity Forecast Summaries for NPCC, IESO, ISO-NE, NYISO, HQ and the Maritimes are included in Appendix I.

projections have all been factored in, the NPCC Area experiences a net margin increase of 3,197 MW during the peak week.

- New England forecasts a summer peak demand of 26,462 MW with a minimum projected 3,023 MW net margin for its peak week, which is the same as the forecasted coincident NPCC peak week. The margin does not include the short-term capacity and energy purchases from neighboring systems that are anticipated to help serve the electrical demands on the system.
- The NYISO forecasts a summer peak demand of 33,295 MW, which occurs during the week beginning July 8, 2012, the same week as the forecasted coincident NPCC peak week. Accounting for purchases, sales, required operating reserve, planned and unplanned outages results in a projected NYISO net margin for the forecasted NPCC peak week of 1,337 MW. The NYISO forecasted minimum net margin is 1,266 MW during the week beginning June 3. The NYISO forecasts installed capacity of 39,583 MW for the NPCC peak week
- The IESO forecasted weather normal, hourly peak demand for this Summer Operating Period is 23,409 MW and includes the reductions associated with planned conservation, growth in embedded generation, implementation of time-of-use rates and slow economic recovery. The IESO is anticipating a net margin of 4,895 MW on the peak week based on the forecasted weather normal demands. Net margins vary from 4,872 MW to 7,534 MW throughout the Summer Operating Period.
- The Québec Area forecasted summer peak demand (excluding April and May) is 21,142 MW during the week beginning August 12. During summer 2012 Hydro-Québec Installed Capacity will total 42,888 MW in August – 115 MW less than last summer. Tracy oil-fired G.S. has been retired from operations (-450 MW) and some contractual capacity has been reduced by 150 MW. However, since last summer, wind capacity has grown by 398 MW. Other small adjustments have been made to Installed Capacity. During that week, the forecasted net margin is 8,484 MW.
- Since the summer of 2011, Ontario has decommissioned 980 MW of coal at Nanticoke G.S. and registered 314 MW of new renewable energy. As well, during the second quarter of 2012, the IESO anticipates to begin commissioning an additional 750 MW of nuclear with the return of the Bruce Unit 2. As a result, the IESO begins the Summer Operating Period with an installed generating capacity of 35,436 MW. By the end of the assessment period, the installed capacity will increase by 750 MW to 36,186 MW. This increase is due to the return of 750 MW from Bruce Unit 1. Two new Bruce – Milton 500 kV lines are also scheduled to added during the second quarter of 2012.
- Phase angle regulators (PARs) are installed on the Ontario – Michigan interconnection at Lambton TS (L4D and L51D) and Keith (J5D) on the Ontario side and at Bunce Creek TS (B3N) in Michigan, representing the four

interconnections with Michigan. Final regulatory approvals have been received, permitting operation of these facilities. Three PARS were placed in service prior to summer 2012 and are being used to manage circulation power flows around Lake Erie, as well as contingencies.

- In the Maritimes, the Dalhousie thermal plant (96 MW + 203 MW) is scheduled to be retired on May 31, 2012. It should also be noted that the Point Lepreau nuclear station is scheduled back on line by October 2012. This plant has been out of service since April 2008 for refurbishment..
- No particular fuel availability problem is foreseen by any of the Reliability Coordinator areas.
- Maritimes and Québec Reliability Coordinator areas are winter peaking systems and expect to be able to provide assistance to other areas when needed up to the transfer capability of the interconnections. It should be noted that Maritimes and Québec net margins exceed transfer capability to other NPCC areas throughout the Summer Operating Period. This is captured in the NPCC Load and Capacity Table AP-7 (Appendix I) as Bottled Resources.
- Summer peaking Reliability Coordinator areas all have some form of demand response programs in place that are expected to provide load relief measures. Some of these programs, such as Interruptible Load Programs, are included in the tables of Appendix I. Other programs, such as the NYISO Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) are emergency procedures involving committed market resources that are treated as capacity resources and reported as Demand Response MW in the table of Appendix I. ISO New England includes all of its active demand resources, which have Forward Capacity Market obligations, under interruptible load.
- There is 5,659 MW of nameplate wind capacity in the NPCC region. After applying a wind derate factor in the respective Reliability Coordinator areas, 611.67 MW count toward capacity. Since the previous summer, 1,260 MW of nameplate wind capacity has come on-line. However, as a result of changes in the derate factor calculations, total wind capacity after derate factors are applied is actually 165.47 MW more than the previous summer.
- Solar Cycle 24 is expected to peak (in terms of sunspot numbers) around 2013. The most intense and disturbed space weather activity typically occurs 2 to 4 years after the sunspot cycle maximum is observed. That phase of activity is expected to happen between 2015 and 2019.
- Environmental constraints, specifically state, provincial and local regulations may have some minor impact at various times through the 2012 Summer Operating Period.

- Communication protocols in place are sufficient to ensure the timely and efficient communications in all Reliability Coordinator areas to maximize the availability of emergency support.
- Use of operating procedures designed to mitigate resource shortages (reducing 30-minute reserve, voltage reduction, and reducing 10-minute reserve) is not anticipated during the 2012 summer period under expected conditions. Slower economic growth than anticipated, coupled with the continuing impacts of conservation initiatives has resulted in a lower overall NPCC demand forecast compared to last year. Furthermore, new resources and transmission capacity resulting from transmission projects planned to be available by this summer are additional factors that act to minimize the expected need for the use of these operating procedures in 2012. Operating procedures are available to maintain reliability for the unlikely simultaneous combination of severe system conditions (such as reductions in anticipated resources, delay of expected transmission projects and/or additional constraints) materializing coincident with higher than expected loads (such as caused by a wide spread, prolonged heat wave with high humidity and near record temperatures).

The CO-12 Working Group believes that NPCC and the associated Reliability Coordinator areas have adequate generation and transmission for the Summer 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 September²) and for 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 2012 Summer Operating Period, the CO-12 Working Group:

- Examined historical summer operational experiences and assessed their applicability for the period to be studied.
- 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 2012 Summer Operating Period. The results and conclusions of the CP-8 assessment are included as Chapter 8 in this report and the full CP-8 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 Summer Operating Period on the adequacy of supply in the shoulder months.
- Coordinated data and modeling assumptions with the NPCC CP-8 Working Group, and documented the methodology of each Reliability Coordinator area in its projection of load forecasts.

² For the purpose of this report, the Summer Operating Period is defined as the week beginning April 29, 2012 to the week beginning September 23, 2012 inclusive.

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

3. Demand Forecasts for Summer 2012

The non-coincident forecasted peak demand for NPCC over the 2012 Summer Operating Period is 110,977 MW. This peak demand translates to a coincident peak demand of 107,052 MW which is expected during the week beginning July 8, 2012. The actual NPCC coincident peak demand during the 2011 Summer Operating Period was 109,754 MW occurring on July 21 at HE 17:00 EDT. This was 2,630 MW less than the all-time NPCC summer peak of 112,384 MW that occurred on August 1, 2006 HE 16:00 EDT. The forecasted coincident peak for summer 2011 was 108,446 MW.

Ambient weather conditions are the single most important variable impacting the demand forecasts during the summer months. As a result, each Reliability Coordinator area is aware that the summer peak demand could occur during any week of the summer period as a result of these weather variables. Historically the peak demands and temperatures between New England and New York can have a high degree of correlation due to the relative locations of their respective load centers. Depending upon the extent of the weather system and duration, there is some potential for the Ontario peak demand to be coincident with New England and New York. It should also be noted that the non-coincident peak demand calculation is impacted by the fact that the Maritimes and Québec experience late spring demands that are influenced by heating loads that occur during the defined Summer Operating Period.

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

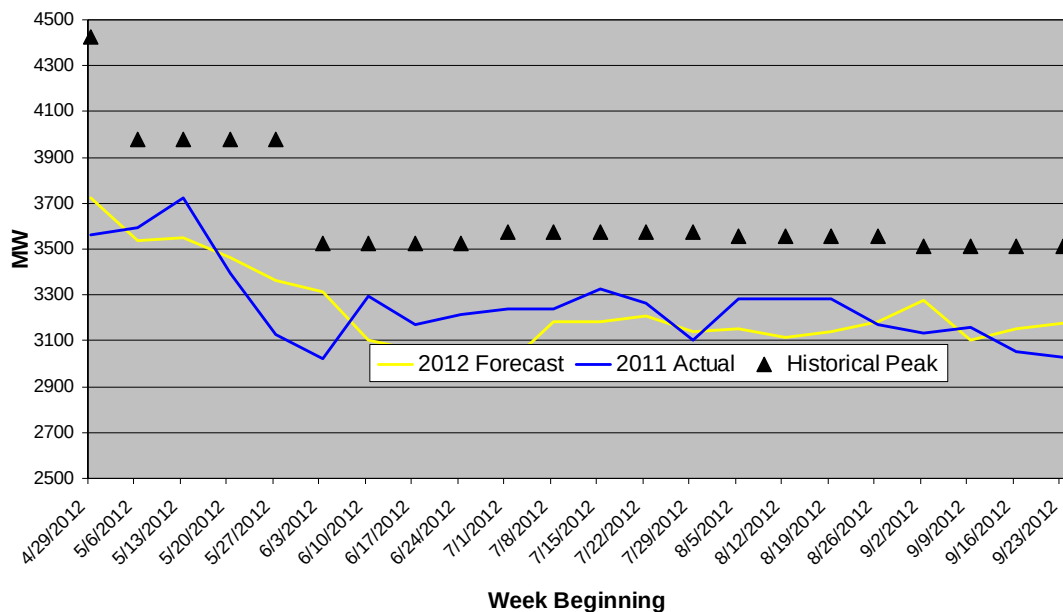
Based on the Maritimes 2012 demand forecast, the forecasted peak for the 2012 summer reporting period, May to September is 3,724 MW and is expected to occur the week of April 29, 2012. This forecasted peak is 0.03 percent lower than last year's actual summer peak of 3,725 MW which occurred on May 16, 2011 at HE 17:00 ET. During the NPCC coincident peak on July 21, 2011 the Maritimes Area demand was 3,274 MW.

The forecasted peak for the NERC RAS summer reporting period, June to September is 3,392 MW and is expected to occur the week beginning September 30, 2012.

It should be noted that the Maritimes 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 Maritimes does not develop an extreme (e.g. 90 percent/10 percent) forecast. The following graph illustrates the weekly Maritimes forecast.

Figure 1: Maritimes Summer 2012 Weekly Demand Profile



New England

The New England Reliability Coordinator area forecasted summer 2012 peak demand is 26,462 MW³ assuming historically-based expected summer peak weather conditions (90.2°F or 32.3°C). This is 1,245 MW (4.5 percent) lower than the 2011 actual metered summer peak of 27,707 MW, and 1,985 MW lower than the 2011 reconstituted summer peak demand of 28,447 MW⁴. The 2012 forecast is 314 MW lower than the 2011 forecast of 26,776 MW⁵. The average annual change in weather normal summer peak is 400 MW (1.9 percent) from 20,830 MW in 1995 to 27,240 MW in 2011. The all-time peak demand for New England is 28,130 MW (occurring at 94°F or 34°C), experienced

³ This forecast takes into account a reduction of 978 MW for passive demand resources (energy efficiency) with capacity supply obligations in ISO-NE's Forward Capacity Market. Without that reduction, the forecast is the reference load forecast of 27,440 published in the ISO New England 2012 CELT Report.

⁴ The metered peak demand of 27,707 MW reflects reductions of 710 MW due to real-time demand response resources that were activated that day as part of ISO-NE's Operating Procedure 4 (OP 4) and 30 MW of Real-Time Price Response.

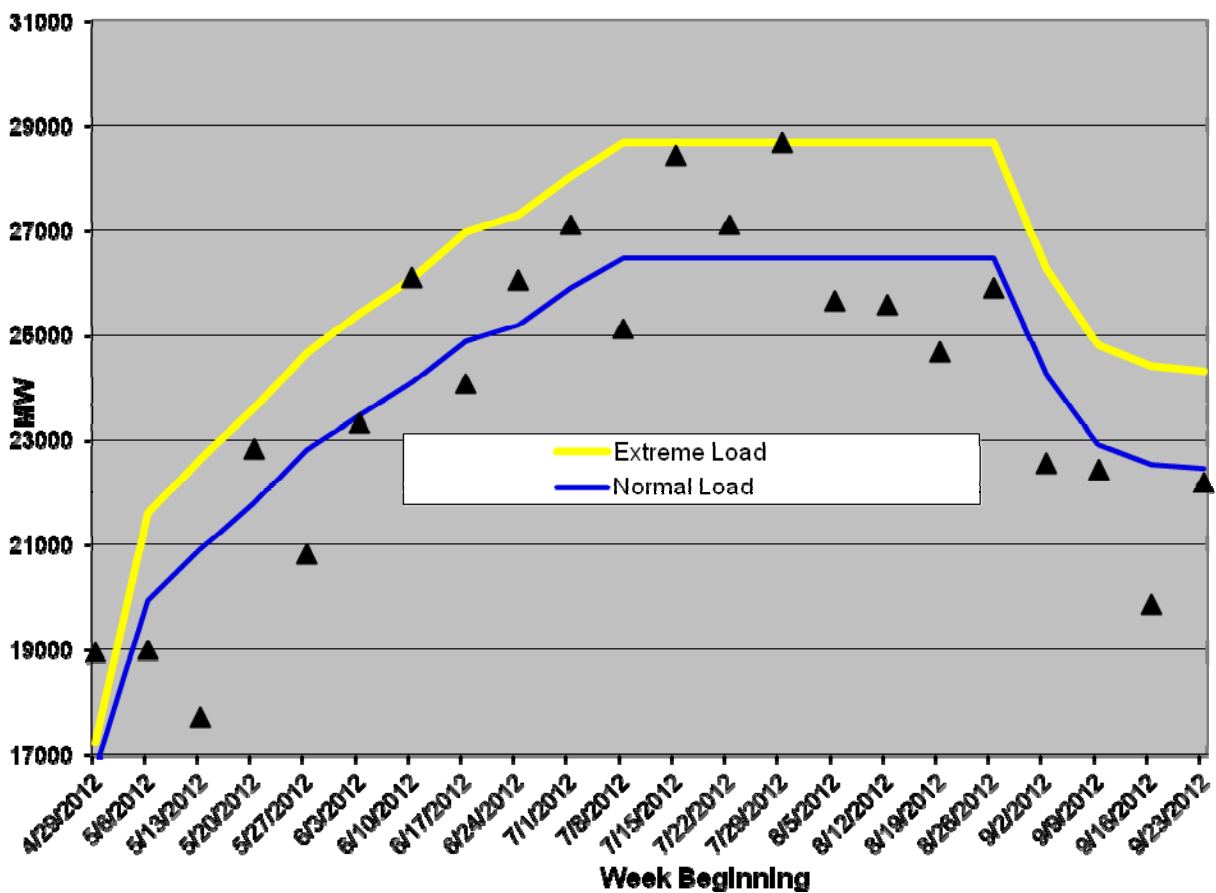
⁵ The 2011 forecasted summer peak demand without the effects of energy efficiency was 27,550 MW.

on August 2, 2006. It should be noted that the all-time peak demand was lower than it otherwise would have been due to the ISO's implementation of Operating Procedure No. 4 — *Action during a Capacity Deficiency* (OP 4) on that day. The peak would have been 28,664 MW without the over 500 MW of demand resources in the ISO-NE Demand Response Program that were called as part of OP 4.

The reference case forecast of 26,462 MW has a 50 percent chance of being exceeded. New England also produces an extreme weather demand forecast that has only a 10 percent chance of being exceeded. The peak demand for this forecast is 28,642 MW.

The following graph illustrates the range of potential peak demands that ISO-NE may experience this summer and compares them to historical peaks. It should be noted that the historical peak values illustrated below are the peak demands reconstituted to reflect power system invoked demand relief procedures (Operating Procedures) that may have been implemented at such times.

Figure 2: New England Summer 2012 Weekly Demand Profile



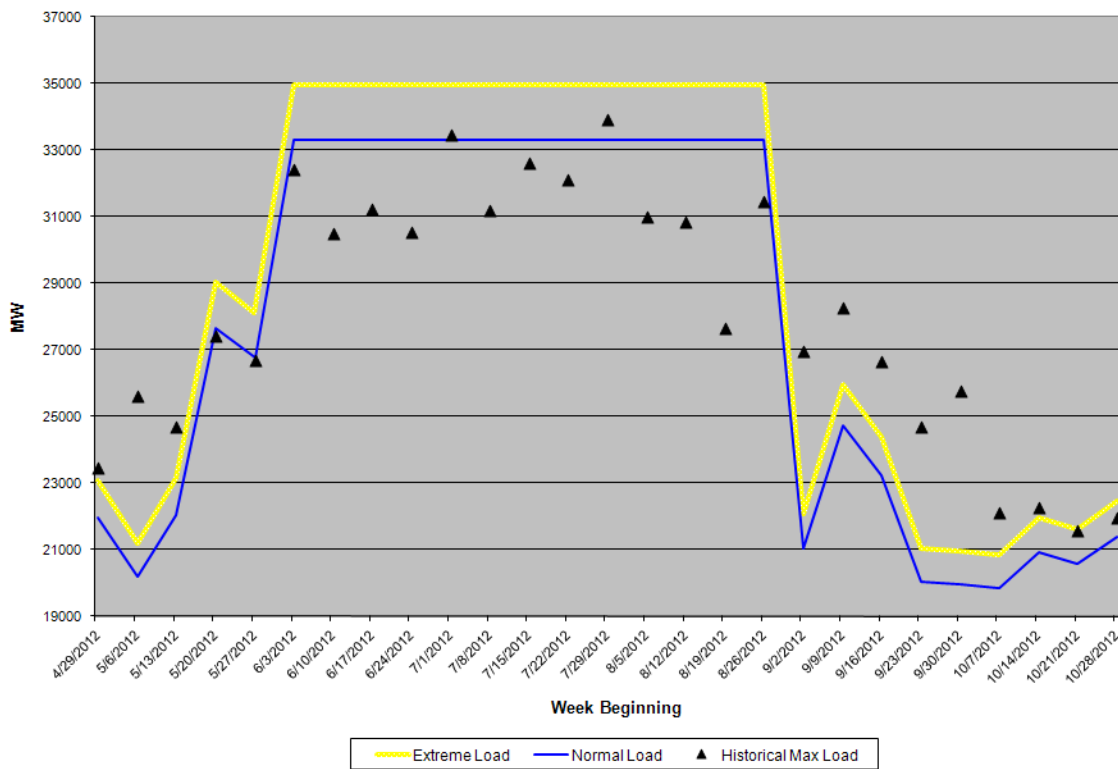
New York

The New York Balancing Authority area peak load forecast for this Summer Operating Period is 33,295 MW, which is 583 MW higher than the forecast of 32,712 MW for the 2011 Summer Operating Period. This forecast load is 1.9 percent lower than the all-time summer peak load of 33,939 MW that occurred on August 2, 2006. The New York 2011 summer actual peak demand occurred on July 22 at hour beginning 3 PM and was 33,865 MW. The daily peak demand observed by New York during the Summer Operating Period occurs during mid to late afternoon.

The forecast is developed by the NYISO using a Temperature-Humidity Index (THI) value of 84.2 degrees, which is representative of weather conditions during peak load conditions. At forecast load levels, a one-degree increase in the THI will result in approximately 610 MW of additional load. Under extreme conditions the peak load could reach 34,959 MW.

The following illustration provides the range of potential peak demands that the New York Area may experience this summer. Note that the weekly load and capacity Table AP-4 of Appendix I reflects the fact that peak conditions may occur during any week from June through August.

Figure 3: New York Summer 2012 Weekly Demand Profile



Ontario

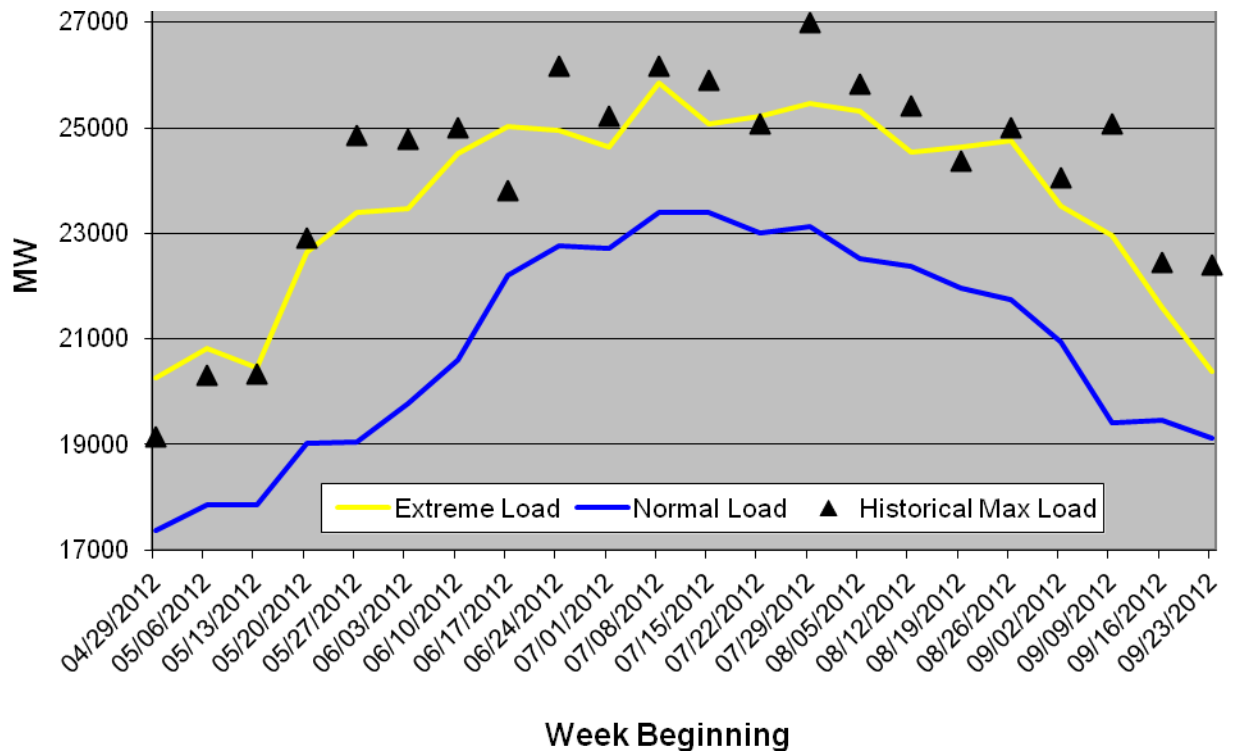
The forecasted weather normal hourly peak demand for this Summer Operating Period is 23,409 MW. This forecast is 7.6 percent lower than last summer's actual peak of 25,342 MW which occurred on July 21, 2011 under warmer than normal conditions. The 2012 summer peak forecast is 0.6 percent lower than last summer's weather corrected peak demand forecast of 23,561 MW. The demand forecast is lower as a result of reductions due to conservation initiatives, growth in embedded generation, time-of-use rates and slow economic recovery.

Weather variations can have a significant effect on electricity demand. The IESO quantifies the uncertainty in peak demand due to weather variations by using Load Forecast Uncertainty (LFU), which represents the impact on demand of one standard deviation in the underlying weather parameters. For this Summer Operating Period, the LFU equates to a potential increase of 937 MW over the forecast peak demand of 23,409 MW. For each month of the Summer Operating Period, there is a 50 percent probability that the actual peak demand will exceed the monthly normal weather peak demand. The LFU value associated with this analysis ranges from 2 to 8 percent of the predicted forecast demands. The highest values of LFU appear during weeks at the end of May and the beginning of June.

Finally, the Summer Operating Period can experience extreme weather driven demands. For this reason, the IESO forecasts extreme weather demands by using the most severe weather experienced in the past thirty years as a reference point. Depending on the week in this assessment period, the extreme weather demand forecast can be from 8 to 24 percent higher than the normal weather forecast. The extreme weather forecast represents a potential increase in peak demand of approximately 2,433 MW over the normal weather forecast for this Summer Operating Period. For the shoulder months of May and September, the impact of extreme weather over normal weather forecast demand can be as high as approximately 3,000 MW.

The following graph shows the demand forecast values for this Summer Operating Period under normal and extreme weather conditions and compares them to historical peaks. The historical peaks are based on the actual load served and include any reductions resulting from demand response programs. The peak demand is forecast for the week beginning July 8, 2012. However, the peak can occur at anytime during the season, from the week beginning June 3, 2012 to the week beginning August 26, 2012.

Figure 4: Ontario Summer 2012 Weekly Demand Profile



Québec

The peak internal demand forecast for the NPCC 2012 Summer Operating Period (May to September) is 22,956 MW, predicted to occur during the week beginning April 29. As can be seen in Figure 5, below, the system's winter peaking characteristic shows up in the fact that space heating load is still present in early May, dropping off slowly as time goes by to finally stabilize into summer loads in June. In this sense, May can be considered a shoulder month for the Québec Area and conditions from June to September are actually more representative of summer conditions in Québec. This time span also represents the NERC summer reporting period.

Hydro-Québec's peak internal demand forecast for the NERC 2012 summer reporting period (June to September) is 20,988 MW, predicted to occur during the week beginning August 12. This represents Québec's official internal peak demand forecast for the 2012 summer and is posted in the NERC 2012 Summer Reliability Assessment. The 2012 forecast is 1.4 percent lower than the 2011 forecast, mainly because of slower economic growth than was anticipated in 2011.

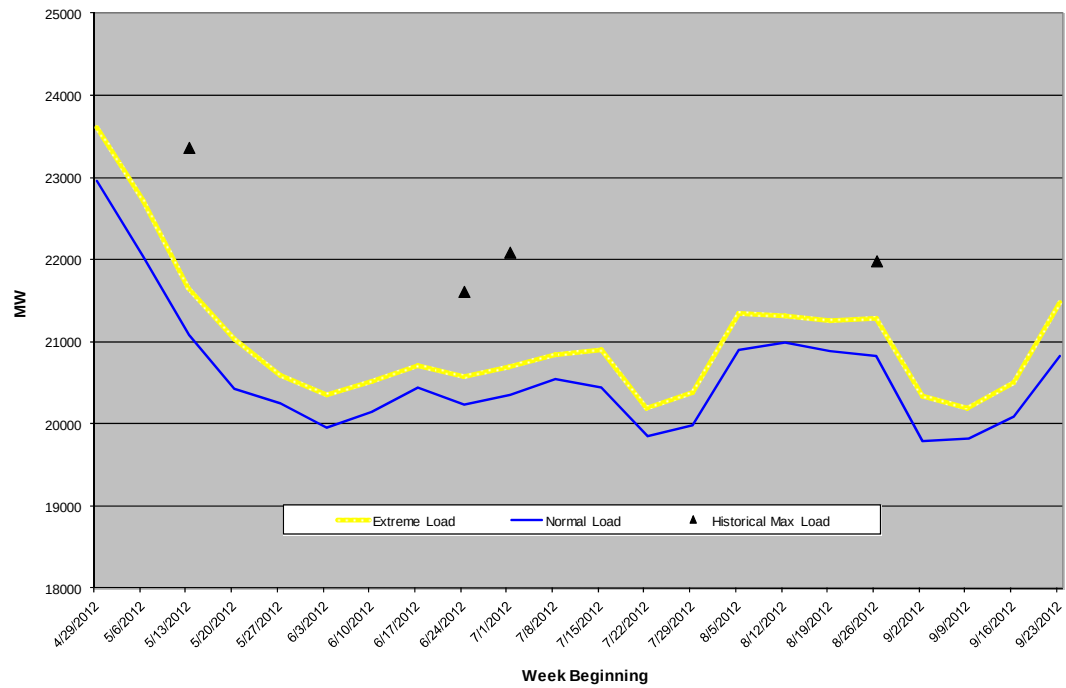
These reference case forecasts have a 50 percent probability of being exceeded. A forecast with a 10 percent probability of being exceeded is also produced for the Reliability Coordinator Area. The peak demand for this forecast is 21,347 MW.

None of the above-mentioned demand values include the supply of 145 MW of load to Cornwall over the Cedars Rapids Transmission (CRT) system (154 MW with losses). This load in the Cornwall area of Ontario is tapped-off the CD11 and CD22 120 kV lines which are part of the Langlois/Les Cèdres to Dennison, New York Interconnection (OASIS path HQT – CORN/DEN). This load is served by the Québec Area. For this reason – in NPCC assessments only – the Cornwall load is included in Québec’s internal load and shows up in Table AP-6 of Appendix I. For example, the demand forecast for the week beginning August 12 is therefore posted as $20,988 + 154 = 21,142$ MW. In NERC Assessments for the Québec Interconnection, the Cornwall load is treated as a Québec Area export and does not appear in the internal demand forecasts.

The actual peak demand for the 2011 summer NERC RAS report period was 21,356 MW. This occurred on July 21, 2011 at 17h00 EDT and was coincident with NPCC’s summer 2011 peak demand. The Québec Area’s all time summer peak is 22,092 MW and occurred on July 8, 2010. There are no Demand Response Programs during Summer Operating Periods in Québec.

The following graph demonstrates the range of potential weekly peak demands on the Québec system for the 2012 summer period and shows monthly historical peaks for the summer period.

Figure 5: Québec Summer 2012 Weekly Demand Profile



4. Resource Adequacy

NPCC Summary for Summer 2012

The following assessment of resource adequacy indicates the week with the highest forecasted coincident NPCC demand is the week beginning July 8, 2012⁶.

Table AP-1 of Appendix I is the NPCC load and capacity summary for the 2012 Summer Operating Period. Appendix I, Tables AP-2 to AP-6, contain the load and capacity summary for each NPCC Reliability Coordinator area. Each entry in Table AP-1 is simply the aggregate of the corresponding entry for the five NPCC Reliability Coordinator areas, with the exception of the sales and purchases which are those external to NPCC.

During the peak week for NPCC the Net Margin is forecasted to be 19,576 MW. However, 9,710 MW of this capacity resides in the Québec and Maritimes Reliability Coordinator areas. If conditions materialize as forecasted, transmission transfer capability between these Reliability Coordinator areas and the remainder of the NPCC Reliability Coordinator areas will limit the use of all of these resources. Transfer Capability from Québec and the Maritimes is calculated from data obtained from Appendix III and Bottled Resources are calculated in Table AP-7 of Appendix I.

The NPCC Net Margins are reduced by 3,754 MW during the peak week for a Revised Net Margin of 15,823 MW.

For the period of mid June to late August NPCC forecast weekly Revised Net Margins vary from 15,811 to 17,723 MW (Table AP-1 of Appendix I).

Table 1 (below) summarizes the load and capacity situation for the forecasted peak week beginning July 8, 2012 compared to the summer 2011 forecasted peak week (week beginning July 17, 2011).

⁶ Detailed Projected Load and Capacity Forecast Summaries specific to NPCC and each Area are included in Appendix I.

TABLE 1: Comparison of Resource Adequacy Between the 2012 and the 2011 Forecasts

All values in MW	2012 Forecast	2011 Forecast	Difference
Installed Capacity	158,052	155,735	2,317
Purchases	305	480	-175
Sales	0	177	-177
Total Capacity	158,357	156,037	2,320
Demand	107,052	108,446	-1,394
Interruptible load	4,597	3,865	732
Maintenance/Derate	21,689	20,498	1,191
Required Reserve	7,975	7,659	316
Unplanned Outages	6,661	6,920	-259
Net Margin	19,576	16,379	3,197
Québec/Maritimes total net margin	9,710	6,244	3,466
Available Transfer Capability	5,956	5,669	287
Bottled Capacity	3,754	575	3,179
Revised Net Margin	15,823	15,804	19

The following are the assessments for each Reliability Coordinator area supporting this overall resource adequacy assessment.

Projected Capacity Analysis by Reliability Coordinator area

Maritimes

The Maritimes Reliability Coordinator area has experienced a net increase of 72.41 MW of nameplate installed wind generation since the 2011 Summer Operating Period. Since the last summer assessment the Dalhousie thermal plant (96 MW + 203 MW) is scheduled to be retired on May 31, 2012. It should also be noted that the Point Lepreau nuclear station is scheduled back on line by October 2012. This plant has been out of service since April 2008 for refurbishment.

During the NPCC forecasted peak week of July 8, 2012, the Maritimes Area Installed Capacity is 7,457 MW. When allowances for firm sales, purchases, known maintenance and de-ratings, required operating reserve and unplanned outages are considered, the Maritimes Area is projecting a net margin of 850 MW for the NPCC peak week. The net margins will range from 734 MW to 1,516 MW (24 to 49 percent) over the Summer Operating Period. The corresponding 2011 summer Maritimes net margin range was 32 percent to 47 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 Area is forecasting normal hydro conditions for the 2012 summer assessment period. Hydro resources are run of the river facilities with limited reservoir storage facilities. These facilities are primarily utilized as peaking units and for providing operating reserve.

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

New England

Based on the reference demand forecast (50 percent chance of being exceeded) and projected available capacity for the 2012 Summer Operating Period, net margins ranging from 3,023 MW to 8,414 MW (11 to 50 percent) are possible. These margins do not include the short-term capacity and energy purchases from neighboring systems that are anticipated to help serve the electrical demands on the system.

The Installed Capacity values in ISO-NE's margin calculations (Table AP-3, Appendix I) reflect the expected summer capability of the generator based on demonstrations or historical generation, and not on the nameplate rating.

The lowest weekly net margin in summer 2012 is about 1,900 MW higher than the lowest week in 2011. The primary reason for this is that this year the Net Margin is based on the generators' Seasonal Claimed Capability (SCC) rather than Forward Capacity Market (FCM) capacity supply obligations (CSOs). The SCC is the demonstrated

capability of the generators, which is generally higher than the CSO, or the capacity that a generator is required to provide to meet the ISO's Installed Capacity Requirement. Also included in the Net Margin calculations are the CSOs of demand resources and imports for the 2011-2012 and 2012-2013 Capacity Commitment Period. Planned generator outages and an allowance for unplanned outages⁷ are also taken into account.

Since demand resources with obligations in the FCM risk being penalized for non-performance, ISO-NE can count on the DR response rate being at or very close to the full MW obligation. This has been confirmed by audits of Active DR in summer 2011, when 95 percent of DR capacity responded, as well as during the July 22, 2011 OP 4 event when 100 percent of Real-Time DR responded.

Under the extreme demand forecast (10 percent chance of being exceeded), net margins could be as low as 843 MW (2.8 percent) during July and August. If a negative capacity margin were to occur during a peak demand condition, ISO-NE would have to implement ISO New England Operating Procedure No. 4 — *Action during a Capacity Deficiency* (OP 4). OP 4 is designed to provide additional generation and load relief needed to balance electric demand and supply while striving to maintain appropriate operating reserves. New England has only experienced summer weather conditions that are consistent with the definition of extreme twice over the past ten years.

OP 4 actions can provide up to an estimated 4,895 MW⁸ of load relief whenever Forward Capacity Market Capacity Supply Obligations from generating resources or imports are insufficient to meet the anticipated load plus Operating Reserve Requirements. All Active DR, totaling 1,127 MW⁹, is only activated via OP 4. Although there are eleven OP 4 actions, ISO New England has only implemented up to the first five actions during the past five years: 1) Implement a Power Caution and allow depletion of 30-minute reserve; 2) dispatch Real-Time Demand Resources; 3) voluntary load curtailment; 4) implement Power Watch; and 5) schedule Market Participant-submitted emergency energy transactions and arrange to purchase Control Area-to-Control Area emergency energy.

Since the summer of 2011, 67 MW of new generation (based on summer ratings) has been put into service in New England, of which 62 MW was wind capacity.

⁷ The allowance for unplanned outages is based on historical trends and is estimated to be between 2,100 MW and 3,400 MW during the summer.

⁸ The amount of load relief can vary based on generator ratings, the circumstances surrounding appeals for voluntary load curtailment, the amount of available demand response, and MWs available from voltage reduction.

⁹ This is the amount of Active Demand Resources with Capacity Supply Obligations in the Forward Capacity Market for the 2012-2013 commitment period, based on the results of the Annual Reconfiguration Auction 3 (ARA3) results.

New York

The NYISO forecasts installed capacity of 39,583 MW for the peak week demand forecast of 33,295 MW. Accounting for purchases, sales, required operating reserve, planned and unplanned outages result in a minimum Net Margin of 1,337 MW for the peak week.

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.

NYISO conducts semi-annual and monthly Installed Capacity (ICAP) auctions. Based on the ICAP forecast load for 2012, the ICAP requirement is 38,622 MW based on a 16.0 percent Installed Reserve Margin (IRM) requirement. The NYISO ICAP forecast is developed prior to the April release of the NYISO Load and Capacity – Gold Book forecast: the ICAP forecast is used for ICAP market analysis. Last year the IRM requirement was 15.5 percent. In addition to the generation resources within the New York 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. Resources within the New York Balancing Authority area that provide firm capacity to an external Area are not qualified to participate in the NYISO ICAP market. When allowances are taken for derates (based on historical performance of 8.9 percent unavailable capacity) and operating reserve requirement, the net available resources will be 34,214 MW, which will be sufficient to meet the New York Balancing Authority area load during the peak load hours.

Since summer 2011, nameplate additions of 612 MW of additional resources have been added or are scheduled to be added to the New York system. There are approximately 496 MW of new certain generation since last summer. There were thirteen retirements in New York since summer 2011 that will impact summer 2012 generation; Astoria Units 2 and 4 (180 and 380 MW respectively), Gowanus Barge Units 1 and 4 (160 MW each), Ravenswood GT 3-4 (43 MW) and Astoria GTs 10 and 11 (32 MW each) are in protective layup, while Barrett Unit #7 (20 MW), Binghamton Cogen (48 MW), Beebee CT 13 (18 MW), Far Rockaway (105 MW), and Glenwood units 4 and 5 (114 MW each) are retired. Total nameplate retirements are 1,403 MW.

Participation in the Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) programs represents an additional 1,912 MW from SCR and 24 MW of EDRP available. EDRP participants voluntarily curtail load when requested by the NYISO. SCR participants must, as part of their agreement, curtail when asked by the NYISO. As of July 2011, there are 5,607 SCR and 200 EDRP resource participants. EDRP and SCR are considered demand response MW in the Load & Capacity Table calculations of net margin (Appendix I); in the NERC ERO reports, the NYISO reports SCRs under Load as a Capacity Resource and EDRP resources as Energy, Voluntary-Emergency.

Ontario

Since the summer of 2011, Ontario has decommissioned 980 MW of coal at Nanticoke G.S. and registered 314 MW of new renewable energy. As well, during the second quarter of 2012, the IESO anticipates to begin commissioning an additional 750 MW of nuclear with the return of the Bruce Unit 2. As a result, the IESO begins the Summer Operating Period with an installed generating capacity of 35,436 MW. By the end of the assessment period, the installed capacity will increase by 750 MW to 36,186 MW. This increase is due to the return of 750 MW from Bruce Unit 1. The wind capacity section has a complete list of all wind farms in service. The installed capacity number includes the nameplate rating of the various wind farms. Taking into account interruptible load, known maintenance/wind derates/bottled capacity, operating reserve, planned and unplanned outages will result in a positive Net Margin of 4,895 MW on the peak week based on the forecasted weather normal demands. Using the forecasted extreme weather demands will reduce the Net Margin for the peak week to 2,205 MW.

The net margin forecast is based on the following assumptions:

- There are no delays with new generating resources coming to service.
- Known outages will proceed as planned.
- Unplanned outages are projected to be 1,350 MW.

Known outages include resources scheduled to be on planned outages, transmission constrained resources and the difference between installed capacity and dependable capacity.

Unknown or unplanned outages represent the average value of forced outages experienced in a similar study period. Dispatchable loads will account for 1,225 MW by the end of the operating period. This quantity is based on participant projected commitments.

The forecasted Net Margins for the Summer Operating Period depict an estimate of the capacity margin that does not include other off-market control actions available to the IESO. For instance, the IESO can institute a 3 percent or 5 percent voltage reduction which reduces the demand by 1.5 to 2.6 percent. For the weather normal peak demand, this equates to approximately 350 MW to 610 MW.

The lowest net margin forecasted is 4,872 MW for the week beginning July 15, 2012. Even though the net margins are all positive for the Summer Operating Period, there are risks associated with this analysis. Actual demands may be heavier than expected due to extreme weather, generators on outage may not return to service as scheduled, or new generations may be delayed coming in service. The IESO will monitor the capacity margin and take appropriate actions to not undermine the reliability of the grid.

Québec

For the 2012 Summer Operating Period, total Installed Capacity for the Québec Reliability Coordinator area will decrease slightly to 42,888 MW (In August) from last summer's capacity. Part of the decrease in installed capacity is due to the retirement of the Tracy oil-fired G.S. Last year, one unit had been retired and Hydro-Québec Production has now proceeded with the complete retirement of the G.S. for 2012. This retirement reduces installed capacity by 450 MW. Moreover, contractual capacity to HQP has been reduced by 150 MW.

Since last summer, however, four new wind generating stations have been commissioned totaling 398 MW. In June, the St-Robert-Bellarmin wind project will be placed in service (80 MW) and in July, one unit of the La Sarcelle hydro G.S. (James Bay system) will be in service (50 MW). The last two La Sarcelle units are expected on-line later on after the Summer Operating Period.

Last summer's assessment showed the three Eastmain-1-A units in service by September 2011. As shown in Table 2 below, the last two units were placed in service in January and February 2012.

The TransCanada Energy (TCE) natural gas generating station (Under contract with Hydro-Québec Distribution) is still under a temporary commercial shutdown agreement. Moreover, Hydro-Québec Production has recently mothballed the La Citière gas turbine G.S. Hence, 787 MW are included in the Known Maintenance / Derates column of Table AP-6 in Appendix I to account for this.

The Known maintenance / Derates column varies from 7,664 MW to 10,419 MW during the 2012 Summer Operating Period. This includes scheduled generation maintenance, wind derating, hydro restrictions, TransCanada Energy derating, La Citière mothballing and other outages during summer.

There are considerable transmission outages during Summer Operating Periods, which may bottle generation over and above usual generation outages. However, this bottling, if it were to prevent transmission clients from serving their firm demand or firm contracts, would be minimized by transmission maintenance outage management. Bottling due to transmission maintenance is therefore not included in both the NERC Summer 2012 Assessment and in this NPCC assessment.

This is a change from past summer assessments and results in higher Net Margins for the Québec Reliability Coordinator area. This causes a corresponding increase in NPCC Net Margins. However, since Québec Net Margins exceed interconnection transfer

capabilities, this excess capacity is bottled in Québec. The end result is that the NPCC Revised Net Margin after bottling sees a corresponding decrease. For the NPCC peak week the known maintenance / deratings in Québec were 12,650 MW for 2011 summer and 8,812 MW for 2012 summer. Corresponding Québec net margins were 4,772 MW for 2011 summer and 8,860 MW for 2012 Summer.

When doing its short term generation/ demand planning, the Reliability Coordinator adds 1,200 MW to its balance sheet to account for frequency regulation reserve, unplanned outages and higher demand forecast. In this report, this is aggregated in the Unplanned Outages column of Table AP-6.

Firm sales of 930 MW in May and 1,130 MW after June 1 are forecasted (991 MW and 1,204 MW including losses as seen in Table AP-6, Appendix I). These sales are to the New England and New York Areas. Additional sales as required by summer peaking areas are expected during the Summer Operating Period. For example, during the NPCC summer 2011 period, Québec sales to neighboring areas were routinely around 5,000 MW.

Required operating reserve is based on 100 percent of the largest contingency plus 50 percent of the second largest contingency as defined in NPCC Regional Reliability Reference Directory #5 – Reserve. Required operating reserve varies depending on system conditions dictating the largest contingency. For this reason, Load and Capacity table AP-6 of Appendix I shows monthly average values calculated from 2011 actual required reserve values. Reserve requirement may reach 2,068 MW during the week beginning August 5.

Under the reference case (50/50) forecast and after due allowance for firm sales, for required operating reserve and for unplanned outages the Net Margin from mid-June to the end of August varies from 8,212 MW to 10,681 MW as can be observed in Table AP-6 of Appendix I. The minimum Net Margin in Québec for the NPCC Summer Operating Period is 5,314 MW, occurring during first week of the NPCC Summer Operating Period. This is a period of rather high maintenance on the system, coupled with a still moderately heavy demand.

Under the 90/10 forecast assumption the Net Margin from mid-June to the end of August varies from 7,836 MW to 10,321 MW. (This is not shown in the Load and Capacity Tables of Appendix I).

For the 2012 Summer Operating Period, TransÉnergie does not foresee any problems in meeting both internal demand and capacity sales while still being able to assist neighboring Reliability Coordinator areas as needed, up to inter-area transfer capabilities.

Generation Resource Changes

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

TABLE 2: Generation Resource Changes 2011 Summer through 2012 Summer

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	In Service Date
Maritimes	Dalhousie (retired)	-299	Coal	May 31, 2012
	Amherst Wind	30	Wind	April 2012
	North Cape	10	Wind	April 2012
	Nova Scotia (multiple wind farms)	32.41	Wind	July 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
	Spruce Mountain Wind	20	Wind	Dec 2011
	Record Hill Wind	50	Wind	Dec 2011
	Granite Reliable Power	99	Wind	Dec 2011
	New Haven Harbor 2-4	130	Nat. Gas/Oil	June 2012
	Milford DFC	8	Fuel Cell	June 2012
New York	Astoria Energy II	617.2	Natural Gas	June 2011
	Upton Solar Farms	32.0	Solar	Oct 2011
	Barrett #7 (Retirement)	-18	Natural Gas	Oct 2011

	Ravenswood GT 3-4 (Retirement)	-40	Natural Gas	Oct 2011
	Howard Wind	57.4	Wind	Oct 2011
	Bayonne Energy	500	Natural Gas	May 2012
	Binghamton Cogen (Retirement)	-47	Natural Gas	May 2012
	Beebee CT 13 (Retirement)	-15	Oil	May 2012
	Gowanus Barges 1 & 4 (Retirement)	-320	Oil	May 2012
	Astoria 2 (Retirement)	-180	Natural Gas	April 2012
	Astoria 4 (Retirement)	-387	Oil / Natural Gas	May 2012
	Astoria GT 10 & 11 (Retirement)	-63	Oil	May 2012
	Far Rockaway #4 (Retirement)	-105	Natural Gas	May 2012
	Glenwood Units 4 & 5 (Retirement)	-228	Natural Gas	May 2012
Ontario	Bruce Unit 2	750	Uranium	2012-Q2
	Bruce Unit 1	750	Uranium	2012-Q2
	Comber Wind Limited Partnership	166	Wind	2012-Q1
	Pointe Aux Roches Wind	49	Wind	2012-Q1
	York Energy Centre	393	Natural Gas	2012-Q2
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 retirement	-450	Oil	Feb 2012
	Mont-Louis	101	Wind	2011-12 W
	Montagne-Sèche	59	Wind	2011-12 W
	Gros-Morne Phase 1	101	Wind	2011-12 W
	Le Plateau	139	Wind	2011-12 W

Maritimes

In the Maritimes, 31.05 MW of new generation (wind) is scheduled for addition during the Summer Operating Period.

New England

Two new generation projects totaling 138 MW, are expected to go commercial in New England before or during the 2012 Summer Operating Period. That total includes 130 MW from three new combustion turbines at New Haven Harbor and an 8 MW fuel cell.

If the 138 MW of new generation is not operational in time for the peak demand period, it will not have an effect on Net Margins because the obligation to supply capacity will be taken on by other suppliers in a reconfiguration auction or through a bilateral contract prior to the beginning of the FCM commitment period on June 1st.

New York

Since the summer of 2011, nameplate additions totaling 612 MW are expected to be available for service prior to the 2012 summer peak. Of that total, 72 MW is wind generation, 500 MW is from the Bayonne Energy Center project, 32 MW is from the Upton Solar Farm project and 8 MW is from miscellaneous landfill gas and small hydro.

Ontario

No delays are anticipated with the return to service of the Bruce 1 and 2 Units.

Québec

As mentioned above, HQP will be commissioning La Sarcelle hydro station's first unit and the St-Robert-Bellarmin wind project will be placed in service for the Summer Operating Period. No delays are expected.

Fuel Infrastructure by Reliability Coordinator area

The following is a self-assessment by each Balancing Authority 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 is very diverse and includes nuclear, natural gas, coal, oil/pet-coke, oil (both light and residual), hydro, tidal, municipal waste, wind and wood. The Point Lepreau nuclear generator in New-Brunswick is currently being refurbished but is expected back in service by October 2012. Fuel supplies are

expected to be adequate during the summer period. Extreme weather conditions should have no impact on the fuel supply to the Maritimes. Responsibility for fuel switching plans lies with the generation owner. All applicable generator 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 #3, New Brunswick (oil or pet-coke), totaling 645 MW. Each facility maintains an adequate supply of its primary fuel.

New England

Historically, fuel supply and delivery options have been readily available to generators within New England during the summer months. For the summer of 2012, ISO New England does not foresee any fuel supply or delivery constraints. However, New England's dependence on natural gas to fire combined cycle generation requires close coordination with natural gas pipeline companies as well as major LNG companies as part of its communications protocol.

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 summer period.

Ontario

The majority of generation facilities operating on the IESO-controlled grid are represented by three basic types of fuel – hydroelectric, nuclear and fossil. The fossil-fueled generation facilities are fired by coal, natural gas or oil. Also, a majority of the oil-fired capability is dual fueled by natural gas and oil. Adequate supplies of all of these fuels are expected to be available and there is no expectation of fuel delivery infrastructure problems for the Summer 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.

The resource capacity assessment in this review of the Summer Operating Period includes forecasts of hydroelectric generation based on historical values of hydroelectric production plus hydroelectric contribution to operating reserve during peak demand hours. This forecasting method is intended to better align the forecasts with expected hydroelectric capability.

Québec

Québec's generation is largely dominated by hydro generating stations located on geographically dispersed river systems and major systems have multi-year storage

capability. Hydroelectric capacity represents about 94 percent of total Installed Capacity. Therefore, to assess the area's energy reliability an energy criterion has been developed stating that sufficient resources should be available to go through sequences of 2 or 4 consecutive years of low water inflows totaling 64 TWh and 98 TWh respectively and having a 2 percent probability of occurrence. (Internal consumption for 2011 was about 185.8 TWh). These assessments are presented three times a year to the Régie de l'énergie du Québec (Québec Energy Board).

Normal hydro conditions are expected for the 2012 summer. Reservoir levels are sufficient to meet both peak demand and daily energy demand throughout the summer.

The Québec Area has 716 MW of gas turbines fuelled by oil or kerosene (of which 280 MW is mothballed at La Citière G.S.), 675 MW of nuclear generation (1 generating station), and one 507-MW combined-cycle gas-fired generating station (Total of 1,898 MW). This accounts for about 4 percent of total capacity resources. The gas turbines are used for peaking purposes in winter; fuel supply is not an issue in this case. The combined-cycle gas-fired G.S. is presently under a temporary shutdown according to a commercial agreement, as mentioned in an earlier section. Wind generation and a very small amount of biomass generation is also present in the Reliability Coordinator area. Coal is not used for power generation in Québec.

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 2012 Summer Operating Period, installed wind capacity accounts for approximately 3.4 percent of the total NPCC Installed Capacity. After applying adequate derate factors, the amount of wind generation counted towards capacity is only approximately 0.3 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.

Table 3 (below) illustrates the nameplate wind capacity in NPCC for the Summer Operating Period and indicates the capacity derating method used. The Maritimes, Ontario and Québec 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. New England and New York reduce the nameplate capacity and include this reduced capacity directly in the Installed Capacity section of the Load and Capacity Table.

Table 3: NPCC Wind Capacity and Derating Methodology

Reliability Coordinator area	Nameplate Capacity 2012 (MW)	Capacity After Applied Derating Factor (MW)	Derating Methodology Used
Maritimes	846	138.57	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	566	97	Based on the average of the median net output during the summer or winter reliability hours during the previous year. The summer reliability hours are the hours ending 14:00 through 18:00 each day of the summer period (June through September) and all summer period hours in which the ISO has declared a shortage event.
New York	1,383	251.8	Uses 81.8 percent derate factor for the summer season.
Ontario	1,727	124.3	Uses seasonal contribution factors based on median historical hourly production values from September 2006 to the present. 92.8 percent derate for June-August, 81.4 percent derate for March-May and Sept.-November, 72.2 percent derate for Dec.-Feb.
Québec	1,137	0	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 for winter peak periods. In summer both HQD and HQP derate factors are set at 100%.

Total	5,659	611.67	

Maritimes

The Maritimes Area currently has approximately 846 MW of nameplate installed wind capacity. Since the summer 2011 period, there 72.41 MW of new wind generation has been added (including the 31.05 MW of wind generation planned during 2012 summer). After applying derates, the current installed wind capacity is 138.57 MW.

Wind projected capacity is derated to its demonstrated average output for each summer or winter capability period. New Brunswick, Prince Edward Island and NMISA individually derate each 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 values.

Table 4: Maritimes Wind Nameplate Capacity

Maritimes Sub-Areas	Nameplate Capacity 2012 (MW)
New Brunswick (Summer Derate)	294
Prince Edward Island (Summer Derate)	173.56
Nova Scotia (On-Peak Capacity Factor)	336.41
NMISA (Average yearly Derate)	42
TOTALS	845.97

New England

The capacity of New England wind resources is based on their Seasonal Claimed Capability, which is the average of the median net output during the previous summer's reliability hours. The summer reliability hours are the hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours

in which the ISO has declared a shortage event. A shortage event is any period of thirty or more contiguous minutes of a system-wide shortage of operating reserves.

For new Forward Capacity Market wind resources without any historical generation data, the capacity is based on measured and recorded site-specific summer and winter data relevant to the expected performance of the intermittent resource (including wind speed data).

ISO New England's total nameplate wind capacity is 566 MW, with 97 MW of that amount counted toward installed capacity.

Table 5: New England Wind Nameplate Capacity

Name	Nameplate Capacity (MW)
Berkshire Wind Power Project	15.00
Granite Reliable Power LLC	99.00
Kibby Wind Power	132.00
Lempster Wind	24.00
Record Hill Wind	50.00
Rollins Wind Plant	60.00
Sheffield Wind Plant	40.00
Spruce Mountain Wind	20.00
Stetson II Wind Farm	25.50
Stetson Wind Farm	57.00
Total Wind Projects <10 MW	43.60
Total	566.10

New York

New York currently has 1,383 MW of installed nameplate wind capacity. Since summer 2011, nameplate additions of 72 MW of wind generation have come on-line. New York applies an 81.8 percent derate factor for wind generation during the 2012 summer season resulting in 251.8 MW counted towards installed capacity.

Table 6: New York Wind Nameplate Capacity

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
Howard Wind	57.4
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
Steel Wind II	15.0
Wethersfield Wind Power	126.0
Total	1,383.6

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 27.8 percent for winter (December, January and February), 7.2 percent for summer (June, July, August) and 18.6 percent for shoulder (remaining months).

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

Table 7: Ontario Wind Nameplate Capacity

Wind Farm	Nameplate Capacity 2012 (MW)	Wind Farm	Nameplate Capacity 2012 (MW)
Amaranth	200	Port Alma	202
Comber	166	Port Burwell	99
Dillon	78	Prince Farm	189
Gosfield	50	Ripley South	76
Greenwich	99	Spence	99
Kingsbridge	40	Underwood	182
Pointe Aux Roche	49	Wolfe Island	198
Total	1,727		

Only 7.2 percent of the nameplate rating is used for wind capacity forecasts for the summer period, this equates to 124.3 MW. The geographic distribution of Ontario wind resources mitigates some of the risk associated with wind capacity variability.

Québec

Wind capacity in Québec is generated by Independent Power Producers. Capacity now in service is 1,057 MW and an additional 80 MW is projected to be in service in June. Three calls for tenders for wind generation have been issued by HQD in the past years and a total of approximately 3,150 MW are scheduled to come on line through year 2015. Approximately 675 MW of new wind capacity is scheduled to go on-line during fall 2012 and will be reported in the next winter assessment. Total wind capacity by the end of 2012 is expected to be around 1,800 MW.

Wind plants presently in service are shown in the table below. (Note that the St-Robert-Bellarmin generating station should be in service June 2012.)

Table 8: Québec Wind Nameplate Capacity

Wind Farm	Nameplate Capacity 2012 (MW)
Le Nordais Cap-Chat (HQP)	57.0
Le Nordais Matane (HQP)	43.0
Mont-Copper (HQP)	54.0
Mont-Miller (HQP)	54.0
TechnoCentre (HQP)	4.0
Baie-des-Sables (HQD, first call)	109.5
Anse-à-Valleau (HQD, first call)	100.5
Carleton (HQD, first call)	109.5
St-Ulric/St-Léandre (HQD, first call)	127.5
Mont-Louis (HQD, first call)	100.5
Montagne-Sèche (HQD, first call)	58.5
Gros-Morne Phase 1 (HQD, first call)	100.5
Le Plateau (HQD, second call)	138.6
St-Robert-Bellarmin (HQD, second call)	80.0
Total	1,137.1

For the 2012 Summer Operating Period, in both the NERC Assessment and in this one, the entire wind generation capacity is derated. In this report, the total nameplate

capacity is reported in the Installed Capacity column in Table AP-6 of Appendix I and the derating is included in the Known Maintenance / Derates column.

As shown in the table above, 212 MW of wind capacity is under contract with HQP. This is not expected to increase in the future.

However, in winter assessments, assumptions regarding capacity contribution of wind power under contract with HQD are different: a capacity credit amounting to 30 percent of nameplate capacity is considered (70 percent of HQD wind capacity is derated).

HQD has conducted detailed wind capacity credit evaluations and has presented its results to the Régie de l'énergie du Québec and to the NPCC CP-8 Working Group. The related report is available (in French only) on the Québec Energy Board website¹⁰. An English article was also presented in October 2010 during a workshop dedicated to wind power impacts on power systems¹¹.

This type of study requires generation hourly chronological series as input to the different models. No historical wind generation data suitable for this study exist in Québec since wind generation has been around for a relatively short time. Thus, HQD mandated a specialized firm to reconstitute 36-year generation hourly chronological series (1971-2006). This has been done by using historical measurements at meteorological stations near wind farm sites, extrapolation techniques and physical models. These data were supplemented by in depth analysis of fourteen critical extreme cold weather events, using high resolution digital weather prediction models from Environment Canada.

Then, wind data were synchronized with equivalent hourly chronological load profiles already developed for load forecasting purposes. The FEPMC model, which is a Monte Carlo simulator developed by Hydro-Québec, was used to evaluate the wind value at peak using the ELCC method. Results were then compared to those obtained from a MARS model with wind power considered as a conventional generation resource through state transition matrices.

Results indicated that a 30 percent Capacity Credit is and will be applicable to wind generation in Québec for winter resource adequacy assessments.

Since the Area's summer loads are low, resource adequacy is only a winter issue. Thus, HQD has decided to not conduct a specific summer study and to apply a 100 percent derate factor (0 percent capacity credit) to its wind generation for summer resource adequacy assessments.

¹⁰ http://www.regie-energie.qc.ca/audiences/EtatApproHQD/Rapport_Contribution%20en%20puissance%20.pdf

¹¹ 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 identifying 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 Reliability Coordinator areas of NPCC under peak demand configurations.

Table 9 below shows transmission additions throughout NPCC since summer 2011.

Table 9: NPCC – Transmission Additions since 2012 Summer and During 2012 Summer

NPCC Sub-Area	Transmission Project	Voltage (kV)	In Service
Maritimes	None for this summer		
New England	Transformer addition at Deerfield Substation in New Hampshire	345/115	Installed-Nov 2011
	Transformer addition at Berry Substation in Rhode Island	345/115	Installed-Dec 2011
	Transformer addition at Wachusett Substation in Massachusetts	345/115	Installed-March 2012
	60 Mvar variable reactor at Coolidge, Vermont	345	June 2012
New York	Luther Forest reinforcement (Rotterdam x Spier Falls)	115	Completed-Summer 2011
	Stony Ridge Project	230/115	Completed-Summer 2011
	Gowanus Ring Bus	345	May 2012
	BP76	230	remain o/s
	Addition of line, bus and PAR-Astoria East-Astoria Annex	345/138	Summer 2012

Ontario	Addition of two Bruce to Milton lines	500 kV	Q2, Q3, 2012
	Phase Angle Regulators ON/MICH	230 kV	April, 2012
	Hurontario station and line uprating	230 kV	Completed
	Porcupine SVC	230 kV	Completed
	Addition of two series capacitors on the Essa-Hanmer lines	500 kV	Completed
Québec	Series Compensation of 35% Inserted into each of the Jacques-Cartier to Chamouchouane 735 kV Transmission Lines (circuits 7024 and 7025).	315 kV	Completed
	Two ± 300 Mvar Static Var Compensators (SVCs) at Chénier 735/315 kV station	735 kV	Completed
	345 Mvar, 315 kV capacitor bank at Duvernay 735/315 kV station	315 kV	Completed

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 the Ontario – Michigan interconnection at Lambton TS (L4D and L51D) and Keith (J5D) on the Ontario side and at Bunce Creek TS (B3N) in Michigan, representing the four interconnections with Michigan. Final regulatory approvals have been received, permitting operation of these facilities. Three PARs were placed in service prior to summer 2012 and are being used to manage circulation power flows around Lake Erie, as well as contingencies.

Inter-Area Transmission Adequacy

The tables in Appendix III provide a summary of the Normal Transfer Capabilities (NTC) on the interfaces between NPCC Reliability Coordinator 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.

The Québec to Maritimes NTC is calculated as 741 MW plus radial loads. Québec to New York FTC may reach 1,800 MW on an hour-ahead basis and depending on operating conditions.

New York to Ontario NTC and FTC are posted as 1,520 MW as the New York – Ontario intertie BP76, which has been out-of-service since January 2008, remains out-of-service until the failed voltage regulator is replaced by April 2013.

Intra-Area Transmission Adequacy Assessment

Maritimes

The Maritimes bulk transmission system is projected to be adequate to supply the demand requirements for the Summer 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

New bulk power transmission facilities that have been placed in service in New England since the 2011 summer period include three new 345/115 kV autotransformers. In New Hampshire, a second 345/115 kV autotransformer was installed at the Deerfield Substation in November 2011. In Massachusetts, a third 345/115 kV autotransformer was installed at the Wachusett Substation in March 2012. Lastly, in Rhode Island a new 345/115 kV substation, named Berry, was completed in December 2011. These facility

additions were needed to address various thermal and voltage issues and are components of larger projects, noted below, that are in various stages of construction.

In June 2012, a new 345 kV 60 Mvar variable reactor will be in-service at the Coolidge Substation in Vermont. It will be available to address high voltage issues that may occur during light load levels in the 2012 summer period. This is one of three new 345 kV variable reactors that will be installed as part of the Vermont Reactors Project.

All significant transmission lines and transformers are expected to be in service through the 2012 summer season with the exception of scheduled transmission projects in Maine as part of the Maine Power Reliability Program (MPRP) construction. In the event of a major unplanned outage of a significant transmission facility and the scheduling of MPRP construction outages, operating procedures will be in place to maintain system reliability.

New York

The Consolidated Edison Gowanus Ring Bus project and Astoria East-Astoria Annex project will be in-service for the summer 2012 operating period. The Gowanus Ring Bus project consists of an upgrade to a ring bus configuration of the existing Gowanus straight bus to accommodate the interconnection of the Bayonne Energy Center. The Astoria East-Astoria Annex consists of a new line from the Astoria Annex 345 kV bus to the Astoria East 138 kV bus with 345/138 kV transformer and PAR.

The Beck–Packard BP76 circuit is expected to be out-of-service through the summer operating period.

Ontario

For this Summer Operating Period, Ontario's transmission system is expected to be adequate with planned transmission system enhancements and scheduled transmissions outages.

Two new 500 kV circuits from Bruce NGS to Milton SS are expected to be placed in service in May. Work at the Bruce switchyards to extend a 500 kV bus and complete the addition of terminal breakers for the two new Bruce – Milton circuits should be completed by the end of the 2012 summer assessment period.

The new 230 kV Hurontario switching station and expanded 230 kV lines are now in service helping to alleviate loadings in the Greater Toronto Area.

A new SVC at Porcupine TS and series capacitors on the two Essa – Hanmer 500 kV circuits have been installed. The Porcupine SVC will improve the ability to maintain an

acceptable voltage profile in the North-east sub-area of Ontario. The increase in transfer capability between northern and southern Ontario attributed to the new series capacitors is waiting for finalized operating instructions. The Queenston Flow West project has not progressed. 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.

Québec

No new significant transmission is being placed in service for the 2012 Summer Operating Period, but a 102 km (63 mile) 315 kV single-circuit line to integrate the La Sarcelle hydro generating station (150 MW) will be in-service for the summer period. However, only 50 MW at La Sarcelle will be in service during the 2012 summer period. Also, as mentioned above, a number of wind generation integration projects are presently ongoing for in-service dates around the end of 2012.

During the Summer Operating Period, some maintenance outages are scheduled on the interconnections. Maintenance is coordinated with neighboring Reliability Coordinator areas so as to leave maximum capability for summer peak periods.

Internal transmission outage plans are assessed to meet internal demand, firm sales, expected additional sales and additional uncertainty margins. They should not impact on inter-area capabilities with neighboring systems.

Appendix III shows a summary of transfer capabilities between the NPCC Areas.

6. Operational Readiness for 2012

The Resource and Transmission adequacy assessments are key elements in determining NPCC's ability to meet the demands of the summer, but they are mere "snapshots in time" or simulations of conditions based on predictions of specific configurations. To mitigate the uncertainty surrounding demand forecasts, forced outages, and other conditions that cannot be controlled or predicted, the Reliability Coordinator areas of NPCC need to be prepared to deal with contingencies in real time.

The following is a synopsis of some of the most prevalent uncertainties affecting the ability to handle the projected demand and the actions NPCC Reliability Coordinator areas can take to mitigate their impact during the 2012 Summer Operating Period.

Reactive Capability of Generators

Heavy demand during the summer period requires that transmission system voltages and the end-use reactive loads be supported by substantial reactive resources in relation to the real power requirements. While static VAR devices and shunt capacitors provide a known quantity of support based on design ratings, the actual reactive capabilities of generators can vary significantly from the design capability.

The following is a discussion of each Reliability Coordinator area's available reactive capability and voltage control capability.

Maritimes

The Maritimes Area, in addition to the reactive capability of the generating units, employs a number of capacitors, reactors, synchronous condensers and a Static Var Compensator in order to provide local area voltage control. Further, the Maritimes is a winter peaking system and the loading of the transmission lines in summer is, in general, lower resulting in lower reactive power consumption.

New England

ISO-NE and its satellite control centers continually monitor voltage and reactive power conditions throughout the system to ensure reliability of the bulk power grid in New England. Major generating stations throughout New England have specified voltage schedules, which are maintained as closely as possible in system operations. In addition to voltage schedules, minimum and maximum voltage limits at several key generating or transmission stations have been established to promote system reliability during adverse voltage/reactive conditions.

New York

Each generator providing voltage support service under the NYISO Tariff to the New York market is required to perform annual testing of reactive capability within

90 percent of its claimed operating capability. The NYISO staff reviews the test data and, if necessary, will perform appropriate voltage analysis to determine operating limits based on the reactive capability testing. In preparation for the Summer Operating Period, the NYISO staff has been reviewing the test data to ensure that all voltage support service providers are in compliance with the testing and reporting requirements for this ancillary service. The NYISO staff has also requested Transmission Owners and Generation Owners to identify local (in plant or station) issues that might limit a particular generator's voltage support capability.

Ontario

The IESO has the authority to test the declared reactive capabilities of generating units. Testing of generating units, critical to the support of key portions of the IESO-controlled grid will be completed before the start of summer. The results of the tests will be compared to the capability assumptions used in studies for the summer. All reactive resources are expected to be fully available for the summer period with no major restrictions. The reactive capability of generators plays an important role in the calculation of the Southern Ontario limits. These limits depend on spare reactive capability at key generating stations.

Québec

Québec is a winter peaking area. During summer periods, reactive capability of generators is not a problem. TransÉnergie does not expect to encounter voltage collapse problems (or even any kind of low voltage problem) during the summer. On the contrary, controlling over voltages on the 735 kV network during off-peak hours is the concern. This is accomplished mainly with the use of shunt reactors. Typically, about 15,000 Mvar of 735 kV shunt reactors may be connected at any given time during the summer, with seven to ten 735 kV lines out of service for maintenance. Most shunt capacitors, at all voltage levels, are disconnected during the summer.

Environmental Impacts

The following are the Reliability Coordinator area assessments discussing environmental related issues.

Maritimes

The Maritimes Area closely monitors air emissions and other environmental discharges to ensure compliance with standards and limits set forth by Canadian Federal and Provincial environmental regulations. For the 2012 Summer Operating Period, there may be occasions when some units are required to be derated in order to meet these regulations. However, these occasions are expected to be infrequent and of short duration.

New England

During extremely hot summer days and/or low hydrological conditions, there may possibly be environmental restrictions on coastal or river-based generating units due to cooling water discharge temperatures. Over past years, such conditions have occurred several times, resulting in temporary reductions in capacity ranging in aggregate, anywhere from 50 MW to 500 MW. These environmental restrictions/reductions are reflected in ISO-NE's forced outage assumptions. It is expected that such temporary reductions will be significantly reduced in the future due to the installation of closed loop cooling systems.

New York

There is a limited possibility that there may be a shortage of available capacity in the New York City metropolitan area due to environmental constraints. High capacity factors on certain New York City peaking units could result in possible violations of their daily NO_x emission limits if they were to fully respond to the NYISO dispatch signals. Significant run time on peaking units, indicating the potential for a violation, could be the result of long duration hot weather events or loss of significant generation or transmission assets in NYC. In 2001, the New York State Department of Environmental Conservation (DEC) extended the agreement it had previously with the New York Power Pool to address the potential violation of NO_x and opacity regulations if the NYISO were required to keep these peaking units operating to avoid the loss of load. Pursuant to the terms of this agreement (DEC, Declaratory Order # 19-12) if the NYISO were to issue an instruction to a Generator to go to maximum capability, in order to avoid loss of load, any violations of NO_x RACT emission limits or opacity requirements imposed under DEC regulations would be subject to the affirmative defense for emergency conditions. This determination is limited to circumstances where the maximum capability requested by the NYISO would involve the generation of the highest level of electrical power achievable by the subject Generators with the continued use of properly maintained and operating pollution control equipment required by all applicable air pollution control requirements.

Ontario

There are many environmental issues that specifically affect the operation of facilities in Ontario during the Summer Operating Period. Compliance with environmental limits are strictly monitored by the facility owner.

There is a possibility that generation will be restricted as a result of environmental regulations regarding cooling water temperatures etc. The timing and the overall impact of any restrictions are unpredictable.

Currently it is the facility owner that would request the appropriate authority to permit a variance from these obligations to assist in a capacity deficiency.

Québec

As mentioned earlier, most generation in Québec is hydroelectric. Gas turbines are used only in winter for peaking purposes. It follows that atmospheric emissions are not of concern for the Summer Operating Period.

Geomagnetically Induced Currents (GICs)

Solar Terrestrial Dispatch Center Forecast

Solar activity is continuing to slowly increase towards what will eventually become a maximum in sunspot numbers sometime next year. However, it is important to remember that the maximum of the sunspot cycle does not correlate with the maximum in geomagnetic activity to which the power grids are susceptible. The maximum in geomagnetic activity lags the sunspot cycle maximum by about 2 to 4 years. As a result, the potential for geomagnetically induced currents (GICs) will continue to slowly increase until the year 2015 to 2017 where a peak should be observed in geomagnetic and GIC activity.

The current phase of the solar cycle is where coronal hole based activity begins to become less influential. It dominated the last 6 years and will now become less predictable as coronal holes start to form and decay more rapidly and are less of an influence due to their smaller sizes. As a result, these long-term projections may become less valuable as guides to future activity, since they are based on stable coronal hole activity. Instead, there should be a greater reliance on the shorter 72-hour predictions.

At the present time, solar physicists are still of the opinion that the current solar cycle will be smaller than most of the solar cycles in the last few decades. But that does not diminish the potential for some large solar flares and geomagnetic storms capable of producing GIC activity. The large solar events tend to occur regardless of the size of the solar cycle. The difference is that there are often a smaller number of other influential events, and the frequency of coronal mass ejections (which are responsible for the disturbances that produce GICs) may be less than if the solar cycle was larger.

Based on the information we have in-hand right now, coronal hole based disturbances will probably dominate first and second weeks of each month. However, their predicted impacts should be low enough to preclude the possibility of observing any substantial GIC activity. In other words, there probably will not be any substantial GIC events that can be directly attributed to coronal holes.

The larger threats now are the transient coronal mass ejections (filament eruptions, solar flares, etc). Since these events cannot be predicted until after they occur, there is no long-range forecast that can be accurately developed for these events. Our largest predictable time-frame is still roughly 72 to 96 hours (3 to 4 days) because of this.

The major active sunspot regions that have been influential in producing GIC activity in the last couple of months have dissipated and are no longer threats. At the present time, there are no large sunspot complexes that we are concerned about.

In summary then, the probability for GIC activity (using coronal holes as proxies, which are now becoming less reliable predictors) will be highest during the first week or two of each month during the coming summer and fall period. If any GIC activity is observed from them, they will likely be fairly inconsequential. There are no other known sources of influential GIC activity at the present time aside from occasional (and unpredictable) filament eruptions, which would be covered in our 72-hour forecasts. Greater weight should be given to the shorter-term forecasts. The possibility of additional major solar disturbances capable of producing influential GIC activity will continue to gradually increase during the next 3 to 5 years, despite the anticipated peak in the solar sunspot maximum next year.

The CO-12 Working Group reminds systems operators that damage incurred through geomagnetically induced currents are cumulative in nature. Many small events can add up. Although there has not been a period of significant GIC activity for a number of years now, there have been numerous periods of small events during the solar minimum. Therefore, it is perhaps prudent to remind system operators that large events may not be necessary to cause equipment malfunction.

NERC Special Reliability Assessment Report¹²

On February 29, 2012, the North American Reliability Corporation (NERC) released its 2012 Special Reliability Assessment Report: Effects of Geomagnetic Disturbances on the Bulk Power System. This effort was one of the key steps identified in the High-Impact, Low-Frequency Event Risk to the North American Bulk Power System report completed by NERC and the Department of Energy in June 2010. The report offers a comprehensive look at multiple and complex issues to evaluate geomagnetic disturbance (GMD) effects on power systems and on their equipment. Issues and subjects such as space weather, forecasting, effects on transformers, protection and control, power system analysis, mitigation, etc. are treated in this report.

According to the report, loss of reactive power is the most likely outcome from a severe solar storm centered over North America. Significant losses of reactive power could lead to voltage instability and, if not identified and managed appropriately, power system voltage collapse could occur.

The report also assessed the vulnerability of high voltage transformers to GMDs. Some transformer types, as well as transformers nearing their end of life were found to be at

¹² See: <http://www.nerc.com/files/2012GMD.pdf>

risk from geomagnetically induced currents. Overall, recommendations from the report span five functional areas:

- Equipment and system design
- Modeling and simulation
- Situational awareness and forecasting
- Alert notification and response
- Training and education

Historical Review

Hydro-Québec TransÉnergie publishes (internal publication) a yearly report¹³ summarizing geomagnetic activity on its system. The following table of selected data is drawn from this report. The table shows both the number of documented storms and intensity level in the past 9 years. Observations confirm that solar activity was indeed very low in 2009 with a slight pickup in 2010 and a definite recovery in 2011. The total number of documented storms dropped from 28 in 2005 to 2 in 2009. In 2011, there were 11 documented storms, two of which reached the K8 index. Concerning Cycle 23, which ended in 2008-2009, the outstanding years were 2003 and 2005. These two years were characterized by a high number of events and high storm intensities and, on HQT's system, high harmonic content and high voltage asymmetry values during events.

¹³ Orages géomagnétiques Rapport annuel 2011 (TransÉnergie's 2011 Annual Report on Geomagnetic Disturbances), March 2012

TABLE 10: Summary of Documented Storms¹⁴

	2011	2010	2009	2008	2007	2006	2005	2004	2003
Documented storms	11	5	2	6	7	11	28	10	39
Kp max = 9	0	0	0	0	0	0	3	3	3
Kp max = 8	2	0	0	0	0	1	1	1	2
Kp max = 7	2	1	0	1	1	1	8	1	11
Kp max = 6	7	4	2	5	6	9	16	5	23

Maritimes

The Maritimes did not experience any significant disturbances in 2011 and no major problems are anticipated for 2012. The Maritimes Operating Procedure is consistent with NPCC Operating Procedures for GIC activity.

New England

In the case of a geomagnetic storm alert of level K index 6 or higher, the System Operators are automatically informed. When receiving a geomagnetic storm alert from the ISO's STD notification software predicting at least a 40 percent probability of activity at levels of Kp 7 or greater, the situation is evaluated and the appropriate steps are taken to mitigate the situation. Examples of these steps are: discontinue maintenance work and restore out-of-service high voltage transmission lines; maintain system voltages within acceptable operating range to protect against voltage swings; and adjust the loading on inter-Area ties to 90 percent or less of their security limits.

During 2011, New England experienced no solar activity that affected transmission system operations.

New York

¹⁴ From TransÉnergie's report: Orages géomagnétiques Rapport annuel 2011 (TransÉnergie's 2011 Annual Report on Geomagnetic Disturbances), March 2012

No effects on the power system were observed that were attributed to GIC activity. During 2005 additional GIC monitoring capability was added in the NYISO control room that displays the current in a transformer neutral at the East Fishkill substation. No effects due to GIC activity occurred in 2011 and significant GIC effects are unlikely, but possible in 2012.

Ontario

The IESO has procedures consistent with NPCC Operating Procedures for GIC activity. When receiving a geomagnetic storm alert from the Geomagnetic Storm Mitigation System (GSMS) of K7 or greater, market participants will be informed via System Status Reports and actions will be taken to mitigate the situation. Actions in the past have included the recall of certain planned transmission outages and the starting of additional generators beyond normal requirements.

Québec

In 2011, the Québec system experienced 11 documented storms, two of which had a K index of 8. There were only 2 storms in 2009 and 5 in 2010. In 2008, the Solar Cycle 24 Prediction Panel¹⁵ confirmed that Cycle 24 had actually begun in March 2008 $\pm$ 6 months and was heading towards a maximum around March 2013. Hydro-Québec TransÉnergie is now seeing Solar Terrestrial Dispatch Center (STDC) alerts with a Kp index greater than 8. After four years without any STDC alerts (2007 to 2010), one was triggered in September 2011 and two more in January and March 2012. These events led to the application of appropriate procedures and impacted operations. Maximum harmonic content during storms is also going up: 1.4 percent in 2009, 2.1 percent in 2010 and 2.5 percent in 2011.

Operating Procedures

Detailed NPCC directories, operating criteria, procedures and guidelines provide the NPCC Reliability Coordinator/Reliability Coordinator areas with the necessary information to develop and maintain a concise set of operating procedures that are relevant to maintaining the security of their respective Areas by observing local operating parameters. Listings and descriptions of the NPCC documents related to operational readiness for the Summer Operating Period are summarized in Appendix V.

NPCC has completed Phase 1 of the process to convert all existing NPCC criteria, procedure and guideline documents to directories. Phase 2 of that process is presently underway. All criteria, with the exception of the A-10, "Classification of Bulk Power

¹⁵ The Solar Cycle 24 Prediction Panel is made up of scientists from the National Oceanic and Atmospheric Administration (NOAA), from the National Aeronautics and Space Administration (NASA) and from the International Space Environment Services (ISES).

System Elements” have been converted to directories. Directories took the requirements specified in NPCC criteria “A” documents on a particular topic and placed them into the body of the directory. The Appendices in the directories do not specify requirements but generally include information on how to put the requirements into use. Some existing operations guideline “B” and procedure “C” documents will remain in place and will not be included in the set of NPCC specific-topic directories. Since the Reliability Assessment for winter 2011-2012, the following revisions to NPCC operations-related documents which define or include operating procedures have occurred:

- A new NPCC Regional Reliability Reference Directory #6 – Reserve Sharing Groups document was completed and approved and has been in place since April 2012. It is a new document, which provides the framework for Regional Reserve Sharing Groups within NPCC and establishes the requirements for them.

Phase 2 of the NPCC document conversion process is underway and its objective is to convert the existing directories to NERC standard-type requirements format.

Several conference call mechanisms are in place to support NPCC Reliability Coordinator/Reliability Coordinator area system operations. These include:

- Emergency preparedness conference calls, which enable operational security entities in NPCC and neighboring regions to communicate current operating conditions and to facilitate the procurement of assistance under emergency conditions. These calls may be initiated upon the request of any Reliability Coordinator and are coordinated by NPCC Staff. Due to the commercially sensitive real-time nature of the material discussed, only signatories to the NERC Confidentiality Agreement for Electric System Security Data may be party to these calls. During 2012 three emergency preparedness calls were held during a period of very cold temperatures in early January.
- To be prepared to deal with the constantly changing conditions on the power system, NPCC routinely conducts weekly operational planning calls between Reliability Coordinators to coordinate short-term system operations. Each Reliability Coordinator area in NPCC is required, under Directory #1, Appendix F “Operational Planning Coordination”, to review its coming twelve-week Net Margin projection on a weekly basis and to communicate this information to NPCC for review during the weekly conference operational calls. These calls are held in accordance with Appendix F. In addition to this review of twelve-week Net Margin projections, the weekly conference call discusses demands, resource availability and scheduled and forced transmission outages for the coming ten-day period, as well as any other information that may impact operations
- A daily morning conference call is held among the control room operators from each NPCC Reliability Coordinator area and NPCC Staff. This call allows communication of any present or anticipated areas of concern for operation.

- Situation awareness displays that provide near real time selected system data were introduced into the NPCC Reliability Coordinator control rooms and NPCC office in June 2009. This development of the displays was led by the NPCC CO-08 Operations Managers Working Group. In parallel with that effort similar displays were provided to FERC and NERC. Development activity is continuing between NERC, FERC and the Reliability Regions on the development of a second generation of these displays, which would include more extensive system information.

Each Reliability Coordinator area has complemented the NPCC Directories, Criteria, Procedures and Guidelines with instructions as they apply to their local conditions.

Maritimes

The Maritimes Operating Procedures are in compliance with the NPCC Operating Procedures and are supplemented with local procedures.

New England

ISO-NE continually reviews and updates as necessary the Market Rules and Operating Procedures for New England. Operating Procedures are in compliance with the NPCC Operating Procedures and are supplemented with local procedures. There are no special procedures in place for the operation of the power system during shoulder months.

New York

The NYISO continues to review and refine operating and market processes based on experience gained through the sustained peak load periods of previous summers. In its Emergency Operations Manual, the NYISO defines how it can deploy demand response for forecasted or actual reserve shortages and other emergency conditions. There continue to be refinements to the NYISO Market operation based on the experience gained during peak load period operation, and new products and facilities are being added.

Ontario

The Day Ahead Commitment Process (DACP) addresses reliability issues by reducing the number of import failures and providing more assurance to internal generation. The design provides a commitment to imports and internal generators, with financial guarantees, in order to provide greater reliability. The design also uses a simple commitment process that limits the impacts on market prices and uplifts.

The Day Ahead Commitment Process (DACP) was enhanced and became operational in October 2011.

The Day Ahead Commitment Process improved the efficiency of the previous DACP for scheduling and committing resources, while still ensuring reliability. Revised features included:

- Optimizing energy and operating reserve over a 24 hour dispatch day.
- Optimizing using total costs for committable generators.
- Revised cost guarantee principles and revised/new failure charges
- Exports and linked wheel transactions
- A model for combined cycle facilities that provides better scheduling of these facilities

The IESO continuously reviews and revises all operating procedures to ensure that they are consistent with both NERC and NPCC requirements as well as with the Market Rules for Ontario.

Throughout the Summer Operating Period, additional NERC Certified System Operators will be available to supplement Control Room Operations staff as conditions dictate.

Québec

All operating procedures are in compliance with NPCC and NERC Operating Procedures. Hydro-Québec TransÉnergie has three procedure categories. The first is a set of general procedures pertaining to the operation of the bulk transmission system and inter-Area ties under the jurisdiction of the Control Centre (CCR). This type of document includes common instructions between TransÉnergie and its neighbors, procedures on system reserves, voltage levels, voltage reduction, load-shedding, system restoration and Special Protection Systems (SPS).

The second is another series of general documents relating to Regional Operating Centers and a third category is made up of specific documents relating to individual stations, lines or equipment.

These procedures are updated periodically and/or when the system evolves.

No Operating Procedures in the sense of load shedding, capacity deficiency, etc. are expected to be called during the Summer Operating Period.

Procedures in Shoulder Months

The uncertainties associated with weather variability and maintenance overruns in the spring months can quickly lead to resource shortfalls. Past history has indicated that resource assessment procedures need special attention during this time frame. As a result of these capacity shortfalls, many of the Reliability Coordinator areas have taken actions to prevent a reoccurrence and are described below.

Maritimes

The Maritimes does not have any special operating procedures for the shoulder months.

New England

ISO New England does not have any special procedures for scheduling generator outages during the shoulder months. However, it is recognized that since there is a significant amount of capacity scheduled out-of-service during late spring, the possibility of outage overruns into the summer period may exist. For this reason, the expected return date for these generators will be regularly verified and updated to prepare for the summer period.

New York

NYISO scheduling staff has reviewed the proposed maintenance outage schedules for generators in the Balancing Authority area and have worked with the generator owners to adjust the outage schedules in anticipation of load levels that may be experienced in the weeks prior to or following the peak load exposure period.

Ontario

The IESO performs extensive reviews of reliability procedures on a regular basis. These reviews include procedures for maintaining reserve margins and rectifying negative margins. These procedures are enforced during the shoulder months to ensure that the necessary control actions are taken in the appropriate time frame, if they become necessary to ensure that planning obligations are met.

With lower demands over the shoulder months, a major concern is Surplus Baseload Generation (SBG). This is a condition that occurs when electricity production from baseload facilities, such as nuclear and hydroelectric generation, is greater than demand. During this time, the IESO works together with market participants to mitigate any over-generation conditions. SBG can be addressed by exports and if necessary nuclear reductions and hydroelectric spills. The IESO publishes a report that forecasts for up to 10 days the hours in each day where an SBG condition is forecast to occur.

Québec

There are no special Operating Procedures in the summer or shoulder months because of the winter peaking nature of the system. The lowest Net Margins are seen during the Winter Operating Period. Thereafter, Net Margins increase regularly from April to September then start to decrease slowly as the fall season comes back into the picture. There is some heating load left on the system in early May. Transmission and generator maintenance outage schedules are updated weekly according to the demand forecast. Outages are rescheduled if necessary to account for higher forecasts.

Demand Response Programs

Each Reliability Coordinator area utilizes various methods of demand management. In those Reliability Coordinator areas where market based structures have been implemented or are evolving, there has been a shift in the contractual obligations of the interruptible loads. The move is an attempt to manage load interruption, as a result of demand exceeding resources, by giving industrial and commercial customers the ability to respond to price signals in the wholesale electricity marketplace. Many of these programs are in varying degrees of development. The following is a summary of each Reliability Coordinator area's current demand response programs available or in development to be available for the Summer Operating Period.

Maritimes

Interruptible and dispatchable loads are forecast on a weekly basis and range between 207 MW and 250 MW. They values can be found in Appendix I, Table 2 and are available for use when corrective action is required within the Area.

New England

The Load and Capacity Table for New England (Table AP-3, Appendix I) includes 1,127 MW of active demand resources during the peak demand period of June through August. Active Demand Resources include Real-Time Demand Response and Real-Time Emergency Generation. These resources reduce load when ISO-NE forecasts and/or implements certain actions of ISO New England Operating Procedure No. 4 – Action during a Capacity Deficiency. ISO New England also has 978 MW of Passive Resources that have FCM obligations. Passive DR is reflected as a reduction in the demand forecast. It includes On-Peak and Seasonal Peak Demand Resources, both of which reduce energy demand during peak hours, are non-dispatchable, and include on-peak and seasonal peak resources. On-Peak Demand Resources provide their load reduction during pre-defined peak weekday hours, and consist of measures that may not be weather sensitive such as reductions in lighting and motors. Seasonal Peak Demand Resources must reduce load during weekdays when the load is at least 90 percent of the 50/50 peak load forecast. They consist of non-dispatchable, weather-sensitive measures such as energy-efficient HVAC systems.

In addition to the reliability-based programs, ISO-NE also administers a Real-Time Price Response program. At the time of the 2011 peak demand, about 59 MW was enrolled in that program, and 30 MW responded. Due to its voluntary nature, this program is not included as capacity within the 2012 Summer Operating Period in the New England Load and Capacity Table.

New York

The NYISO has two demand response programs to support system reliability. Demand side resources enrolled in the Emergency Demand Response Program (EDRP) are paid to reduce their consumption by either interrupting load or switching to emergency standby generation when requested by the NYISO. Special Case Resources (SCRs) sell their capacity through Installed Capacity Market auctions and are obligated to provide that capacity when deployed by the NYISO during a demand response event.

The NYISO deployed EDRP/SCR demand response programs on two occasions in the summer 2011. Beginning with the summer 2007, the NYISO implemented a new program, Targeted Demand Response Program (TDRP) designed to increase granularity to the location of EDRP and SCR resources called at the request of a transmission owner to meet local reliability needs.

Both of NYISO's demand response programs for reliability (SCR and EDRP) will be available for summer 2012, and NYISO estimates that a total of 1,936 MW of load relief during peak conditions is considered "reliable." This load relief will be available to support the New York State power system during capacity emergency periods.

Ontario

The IESO utilizes demand response initiatives that consist of reliability and real-time price demand response programs. These include the Demand Response 3 (DR 3) program and the Peaksaver program.

The Demand Response 3 (DR3) program was developed in 2008 by the Ontario Power Authority (OPA) to provide an incentive for participants to lower consumption. DR-3 is a contract based program with currently 286 MW where participants are required to reduce load when called upon in order to get an availability payment and utilization payment upon activation for an actual measured and verified load reduction. Notifications and activation notices for DR-3 are sent to participants based on criteria identified by OPA. These notices will not necessarily coincide with forecasted adequacy shortfalls.

Peaksaver is an economic based demand response program created by the OPA to provide customers with an ability to manage demand during the pre-determined scheduled periods noted for high demand and tight supply. It is a voluntary program and it does not involve any financial settlements. The program provides for up to 40 hours of Load Control Events (activations) annually for specific hours on business days between May 1 and September 30. Activations last up to 4 hours but can be longer to address reliability concerns. The program is triggered when the IESO declares any level of Energy Emergency Alert (EEA1, EEA2 or EEA3) and communicates it using the System Status Report (SSR). If required, the program can also be triggered by primary demands or temperatures above pre-determined levels, or at the IESO's discretion to deal with emergencies.

Québec

Demand response in Québec is limited to two interruptible load programs. These are available during Winter Operating Periods only.

Communications Systems with Operators and Customers

There is normally some time lag for control actions to take effect to rectify a resource deficiency. In the evolving market places there are now many players in Reliability Coordinator areas where at one time, there were only a few. As a result, simultaneous communications need to be timely and efficient for multiple resources to respond to directions by the Reliability Coordinator and quickly mitigate the need for emergency control actions, including the shedding of load.

Below is a summary of the communication medium that each Reliability Coordinator area utilizes to communicate emergency situations with generators, transmitters and customers.

Maritimes

The individual Control Centers within the Maritimes Area provide timely and accurate information regarding the status of the power system to customers via websites, news releases, high volume Interactive Voice Response System and telephone contact through Public Affairs and Customer Services departments or Call Centers.

New England

In the event of a capacity deficiency, ISO-NE's website provides real-time information to stakeholders and the general public regarding the status of the power system and the amount of Emergency Energy Transactions requested during peak periods. In addition, Control Room operations will convey the information to ISO-NE's Customer Service and Corporate Communications Departments so they can make the necessary communications to federal and state regulatory agencies and the media. Operations personnel convey the details of any capacity deficiency to the Local Control Centers and neighboring Reliability Coordinator areas as appropriate.

In addition, ISO-NE creates a seven-day forecast that is posted to the ISO-NE web site.

This posting includes a capacity analysis for the peak hour of each day, detailing the forecasted amount of surplus/deficient capacity for each future day to illustrate anticipated system conditions.

ISO-NE has also recently been working to improve communications with resource contacts, specifically to improve their ability to perform in response to an emergency situation. As a result of generator performance issues during the September 2, 2011 Disturbance Control Standard violation, ISO-NE has implemented changes to Operating Procedure No. 14 (OP 14), *Technical Requirements for Generators, Demand Resources and Asset Related Demands*. These changes pertain to the technical requirements

regarding notifications for equipment failure, display information, dispatch instructions and maintenance of operational data.

New York

The NYISO is continuing implementation of its Inter-Control Center Communications Protocol communications system (ICCP) allowing bi-directional data communication directly from the NYISO control center systems to the generating plants. In normal operation this facilitates the transmitting of schedules and base-points from the NYISO dispatch system to the generators and improve the accuracy and timeliness of generator real and reactive power metering.

The NYISO website now displays information including actual Balancing Authority area load in addition to the real-time zonal pricing information and transmission outage schedules. Market Participants may also access a “dispatcher notes” page that provides information on current NYISO system operating conditions.

Ontario

The IESO publishes System Status Reports (SSR) and daily and weekly Security and Adequacy Assessment (SAA) reports. These reports provide a forecast of future expected system conditions in the IESO administered markets, and assists market participants in making appropriate operational decisions.

The System Status Report (SSR) covers the current day to day-2 and the daily SAA report details days 3 to 14. These two reports supply the Market Participants with detailed adequacy projections on an hourly resolution. The weekly SAA report covers day 15 to day 31. This report provides a daily granularity.

The SSR has capability to identify to Market Participants the following Advisory notices:

- Major Change Advisory – for a major change in expected load, generation or transmission capacity.
- System Advisory – for over/under generation or shortfalls in operating reserve or contracted ancillary services.
- System Emergency Advisory – for an emergency or high risk operating state.
- Market Suspension/resumption Advisory – for suspending/resuming operation of all or part of the IESO-administered markets.

To address global adequacy concerns when there is insufficient energy or capacity available to the IESO-controlled grid or when there are insufficient offers in the real-time dispatch of the IESO-administered markets, the IESO shift staff can also issue a SSR. The SSR can be prepared on very short notice.

To address local area adequacy concerns, the IESO will direct Market Participants to submit offers, either via the Market Participant's dispatch workstation or telephone.

The IESO also recognizes the need to communicate with the general public at times when there might be supply shortfalls. To achieve this, the IESO created a public communications process to ensure that consumers and industries in the general public were given all the information they need to make informed choices. The process for communicating to the general public has proven to be effective.

Québec

Capacity deficiency situations are addressed by a number of procedures, the most important being procedures, instructions and information documents on system reserves. When a capacity deficiency potentially leading to not meeting the reserve criteria is anticipated a system alert is given. The Control Center informs the Reliability Coordinators of neighboring systems via the RCIS and the Transmission Operators in the Québec Reliability Coordinator area are informed by telephone. The NPCC Emergency Teleconference is initiated. Control Center dispatchers then follow Operating Reserves procedures to sustain and/or reconstitute reserves. When the alert has ended, the aforementioned contacts are so informed. Operating Reserves procedures also contain a communications process to be applied during capacity deficiencies.

Capacity deficiency situations can lead to a number of actions on the system called by Control Center Dispatchers ranging from manning and starting gas turbines, recalling outages, through calling interruptible load (when available), importing from neighboring systems, using voltage reduction schemes, calling a public appeal to reduce consumption up to rolling blackouts. Procedures are in place for all of these actions. A procedure has been implemented that identifies the communications with operators, customers and neighboring systems in case of such events on the system. An internal communications scheme is also set up to inform personnel of the event and to set up appropriate working groups.

Communications schemes with customers are set up and updated periodically to inform the public through the Media if a public appeal is called.

Acquisition of Emergency Energy between Reliability Coordinator areas

The following is a summary of the ability to transact emergency energy between adjacent Reliability Coordinator areas.

Maritimes

The Maritimes, through existing agreements with neighboring Reliability Coordinator areas, namely, ISO-NE and TransÉnergie, has established procedures for the acquisition of emergency energy.

New England

When the New England Reliability Coordinator area experiences or is forecasted to experience a shortage of operating capacity, ISO-NE will request Market Participants to submit Emergency Energy Transactions (EETs) through the Market System. If the amount of EETs submitted is not adequate, or if there is not enough time for the market to respond, ISO-NE has existing interconnection operating agreements with its neighboring Reliability Coordinator areas to procure emergency energy.

New York

The NYISO maintains Joint Agreements with each of its adjacent Reliability Coordinators that include provisions for the procurement, or supply, of emergency energy, and provisions for wheeling emergency energy from remote areas if required.

Ontario

The IESO have negotiated operating agreements with the adjacent Reliability Authorities. These operating agreements contain provisions for the transaction of emergency energy into and out of Ontario and are only implemented in the event that market based solutions are ineffective.

Québec

Entities in the Area have agreements with all neighboring Reliability Coordinator areas that detail conditions and procedures for exchanging emergency energy. A procedure supervises the Control Center actions and communications for this energy exchange.

Training Programs

The Reliability Coordinator area system operators must receive training to obtain sufficient Continuing Education Hours (CEHs) to maintain their certification. In addition, new system operator candidates receive extensive training to learn to become competent to perform all job tasks and to prepare for the NERC system operator certification exam. The NERC System Personnel Training standard (PER-005-1) was approved by NERC in February 2009 and was approved by FERC on April 1, 2011 for U.S. entities. In Canada the regulatory authority in each province determines the applicability of the standards in individual provinces. The date when each PER-005-1 requirement is enforceable is tied to the approval date and is specified in the standard. This standard establishes updated requirements for the training programs of the NPCC Reliability Coordinators, Balancing Authorities and Transmission Operators (RCs/BAs/TOPs) for system operators. The NPCC RCs/BAs/TOPs have been making revisions to their training programs to fulfill all requirements in the standard. This requires use of a systematic approach to training. The systematic approach to training entails: 1) a list of BES company-specific reliability-related tasks performed by its System Operators, 2) learning objectives and training materials based on the task list, 3) delivery of the training, 4) verification that each of its System Operators are capable of

performing each assigned task and 5) at least 32 hours of emergency operations training each year.

The CO-2 Working Group members are actively working on changes to the training programs and are developing documentation within their programs to satisfy PER-005 requirements. CO-2 members are sharing their approaches and looking for consistent ways to do this.

To promote coordination and shared training experiences among system operators in the NPCC Reliability Coordinator areas the NPCC CO-2 Working Group annually conducts spring and fall System Operator Seminars. NPCC will conduct its spring 2012 69th System Operator Seminar in Boston, Massachusetts on May 2-3, 2012, for system operators to share views and experiences.

The agenda and Seminar are developed by the NPCC CO-2 Working Group on System Operator Training, in conjunction with the CO-8 System Operations Managers Working Group.

Maritimes

The Member companies that comprise the Maritimes routinely conduct their own operator training sessions and participate in NPCC Operators training seminars. The operators in the New Brunswick Control Center and Nova Scotia Control Center are NERC certified. The Maritimes participates in the CO-2 Working Group on System Operator Training.

New England

Throughout the year, ISO-NE Operators and Local Control Center personnel participate in training sessions in preparation for both the summer and winter peak demand periods.

During the training sessions, applicable NERC Standards, NPCC procedures and ISO New England emergency operating procedures are reviewed in detail. The summer capacity assessment is also reviewed along with area-specific voltage control issues and intra-area communication procedures. ISO-NE System Operators are NERC Certified Reliability Operators, and ISO-NE Operations Training is a NERC-Approved Continuing Education provider. ISO-NE System Operators maintain their NERC Certifications by use of Continuing Education Hour (CEH) credit obtained by attending NERC-approved ISO-NE Operations Training courses. The ISO-NE Operators are required to obtain 200 CEH credits over the course of three years to maintain their Reliability Operator Certification. Cycle 2 of that training each year deals with the Summer Capacity situation and preparing the operators for potential problems by reviewing the procedures used in the mitigation of capacity deficiencies, both in the classroom as well as by solving capacity deficient scenarios in the Operations Training and Testing Simulated Environment (TTSE) Simulator. This involves all potential efforts up to and including shedding of firm customer load to resolve the capacity deficiency.

New York

NYISO Dispatcher Training staff will be conducting two weeks of in-house training for each crew of NYISO dispatchers prior to the summer of 2012. These sessions will address operations issues, updates on NERC standards, NPCC policy changes, updates on NYISO market operations and market design, updates to NYISO applications and procedures, and simulations of emergency situations.

NYISO Dispatcher Training staff will also present one week System Operator Training Seminars for a combined audience of the NYISO and New York Transmission Owner (TO) dispatcher crews. This program will review selected NYISO operating policies, recent system events, the system outlook for the Summer 2012, and address issues of mutual concern to both TO and NYISO dispatchers. NYISO emergency operation procedures (Back-up Operations, Alternate Control Center operation, and Restoration) will be reviewed in preparation for the spring drills.

Ontario

The IESO continues to be committed in providing a training program for control room and support staff in order to maintain awareness of current and new NERC, NPCC and local operating procedures.

In preparation for this Summer Operating Period, the IESO has set aside time in the training program for Shift Operations staff to review reactive dispatching techniques and emergency procedures. Additionally, the IESO plans and participates in drills and exercises on a regular basis to hone emergency preparedness skills and test procedures by simulating real events.

Finally, each shift at the IESO will perform a Rotational Load Shedding simulation exercise prior to the start of the Summer Operating Period. These exercises will test procedures and training as well as verify communication methodologies and validate revised load shedding schedules.

Québec

All Québec Control Center operators are certified as Reliability Coordinators. In accordance to the NERC Certification Program, TransÉnergie complies with the three-year training program including a number of NERC pre-approved training hours.

All new operators must pass the NERC exam before being assigned to a control desk and must then comply with the three-year training program as do all other operators.

Moreover, TransÉnergie supports a number of in-house training programs for operating personnel concerning all operational aspects on the system.

Post-Seasonal Assessment and Historical Review

Summer 2011 Post-Seasonal Assessment

The NPCC coincident peak demand occurred on July 21, 2011 at 17h00 EDT. Demand was then 109,754 MW. The following table compares the NPCC resources forecast for the peak week in 2011 summer versus the actual resources at the time of the peak.

TABLE 11: Summary of Resources on July 21, 2011 HE 17h00

All values in MW	July 21, 2011 HE 17:00 Actual Peak	July 17, 2011 Week Forecast	Difference
Installed Capacity	150,220	155,735	-5,515
Purchases	4,697	480	4,217
Sales	6,927	177	6,750
Total Capacity	147,990	156,037	-8,047
Demand	109,754	108,446	1,308
Interruptible load	3,270	3,865	-595
Maintenance/Derating	21,380	20,498	882
Required. reserve	7,801	7,659	142
Unplanned Outages	1,485	6,920	-5,435
Net Margin	12,723	16,379	-5,539
Québec/Maritimes total net margin		6,244	
Available Transfer Capability		5,669	
Bottled Capacity		575	
Revised Net Margin		15,804	

The sections below describe each Reliability Coordinator area's summer 2011 operational experiences during the NPCC coincident peak, which occurred on July 21, 2011 at hour ending 17:00.

Maritimes

Coincident demand was 3,274 MW.

All major transmission and interconnections were in service.

New England

Coincident demand was 26,410 MW.

Operating procedures were required on the day of the coincident peak. ISO-NE implemented OP 4 on July 22, 2011 due to extreme hot weather and higher than expected forced outages and reductions.

New York

Coincident demand was 33,454 MW.

No fuel supply, transmission or reactive capability issues.

Ontario

Coincident demand was 25,260 MW.

Demand was higher than the forecast, despite conservation initiatives and growth in embedded generation, due to hotter weather and economic recovery.

Québec

Québec internal demand coincident to the NPCC peak was 21,356 MW. This is also the Québec summer 2011 peak demand. Transfers to neighboring areas were approximately 6,300 MW.

The all-time summer peak demand record is 22,092 MW in July 2010. No resource adequacy event occurred during the 2011 Summer Operating Period.

Historical Summer Demand Review (Pre-2012)

The historical non-coincident peaks and the 2012 forecast peaks are indicated in Table 12 below for each NPCC Reliability Coordinator area.

Table 12: Historical Peak Demands by Reliability Coordinator Area Occurring May to September And Total Non-Coincident NPCC Demand (MW)

Year	Ontario ¹⁶	Maritimes	New England	New York	Québec	Total NPCC Demand
1995	21,674	2,958	20,499	27,206	17,960	90,297
1996	21,378	2,937	19,507	25,587	18,193	87,602
1997	21,613	3,252	20,569	28,700	17,983	92,117
1998	22,443	3,314	21,406	28,166	18,463	93,792
1999	23,435	3,249	22,544	30,311	18,965	98,504
2000	23,222	3,630	22,049	28,138	20,600	97,639
2001	25,269	3,640	24,967	30,983	20,052	104,911
2002	25,414	3,731	25,348	30,664	20,525	105,682
2003	24,753	3,901	24,685	30,033	20,551	103,923
2004	23,976	3,635	24,116	28,433	21,949	102,109
2005	26,160	3,821	26,885	32,075	22,365	111,306
2006	27,005	3,385	28,127	33,939	21,361	113,817
2007	25,737	3,886	26,145	32,169	21,411	109,335
2008	24,195	3,675	26,111	32,432	21,488	107,901
2009	24,380	3,566	25,100	30,843	21,141	105,030
2010	25,075	3,497	27,102	33,452	22,092	111,218
2011	23,342	3,725	27,707	33,865	21,356	111,995
2012 Forecast	23,409	3,724	27,440	33,295	21,142	109,078

¹⁶ 20 minute Peak Demand 1993 to 2001, peak hourly demand thereafter

Winter 2011/2012 Review

NPCC

The sections below describe briefly each Reliability Coordinator area's 2011/2012 winter operational experience. Total NPCC non-coincident peak demand was 108,135 MW for the period.

Maritimes

The forecasted peak for winter 2011-2012 was 5,552 MW.

Peak demand occurred on February 13, 2012.

Demand was 4,963 MW.

Control actions were not required.

New England

Peak demand occurred January 4, 2012.

Demand was 19,905 MW.

Implementation of Operating Procedure 4 (OP 4) was not required at the time of the peak. However, OP 4 was implemented on the morning of December 19, 2011 due to forced generator reductions/outages and loads running over the forecast.

New York

The forecasted peak for winter 2011-2012 was 24,533 MW.

Peak demand occurred January 3, 2012.

The demand was 23,901 MW.

No particular issues.

Ontario

The winter peak demand of 21,649 MW occurred on January 3, 2012. This was 3 percent lower than the forecasted demand of 22,311 MW. Peak demand was lower than the forecast due to warmer weather conditions.

Québec

Demand, Imports and Exports, and Load Management

Winter 2011-2012 was much warmer than normal. In Montréal, average temperatures for winter were 3.4 °C (6.1 °F) higher than mean temperatures. This was the warmest winter since 2001-2002 and the second warmest since 1942. Internal demand was correspondingly low. Only ten peak days showed demand values above 33,000 MW.

Internal peak hourly demand for winter 2011-2012 was established to be 35,481 MW on Monday, January 16, 2012 at 8h00 EST. This value includes 1,388 MW of interruptible demand that was used at the time. Therefore, actual metered demand (Served Internal Demand) was 34,093 MW at peak. The annual forecast was 37,209 MW. Transfers to neighboring areas at the time of peak were 3,512 MW.

Montréal temperature at peak time was -18 °C (-0.4 °F) and wind speed was 9 km/hour (6 mph). Temperatures in most other areas of the province were somewhat colder than in Montréal but nowhere near usual peak period temperatures.

Generation and Reserves

At the time of peak, maximum generation capacity was about 42,290 MW, including Churchill Falls, various firm contracts, wind capacity and the TransCanada (T.C.E) gas generating station.

Generation outages totaled 1,484 MW. Hydraulic, wind, and mechanical restrictions totaled 1,980 MW. Thus, total available capacity was about 38,826 MW.

Wind farm generation output was approximately 425 MW, corresponding to about 40 percent of installed capacity.

Thirty-minute operating reserve at peak time was 2,711 MW, 1,211 MW over the reserve requirement.

Transmission

Major transmission additions reported in the NPCC Reliability Assessment for Winter 2011-2012 were in service for the Winter Operating period (two SVCs at Chénier, series compensation at Jacques-Cartier and 345 Mvar capacitor bank at Duvernay). Synchronous condenser CS23 at Duvernay was still out of service. The repaired transformer is due back during summer 2012. Shunt capacitor availability was slightly lower than the target but voltage support in the load areas was adequate.

No particular transmission condition that affected internal demand or firm transactions occurred during the Winter Operating Period.

7. 2012 Reliability Assessments of Adjacent Regions

ReliabilityFirst Region-PJM

1. Assessment Area Highlights

The purpose of this section is to present summer 2012 projections for the reliability, resources, demand, and transmission infrastructure in the PJM RTO Assessment Area. Data was aggregated using a bottom-up approach with projections based on economic indicators, long-term weather forecasts, and historic load data.

This year's report includes the load and resources of Duke Energy Ohio/Kentucky (DEOK), which was integrated into the PJM RTO on January 1, 2012.

The Reserve Margins for the PJM RTO Assessment Area are based on Anticipated resources. The Anticipated Reserve Margin will remain above the PJM Required Reserve Margin Level during 2012 summer season.

A total of 5,007 MW of capacity have been added since the 2011 summer. According to the PJM's demand forecast, Total Internal Demand has decreased from 154,383 MW to 153,782 MW since the 2011 summer. This equates to an annual growth rate of -0.4 percent.

2. Planning Reserve Margin

The PJM is projecting an adequate Reserve Margin for the 2012 Summer Peak Period of 25.4 percent. The Reserve Margin calculation includes total forecasted load, Existing Certain generating resources, forecasted Demand Side Management (economic DSM treated as a resource and emergency DSM treated as a load reducer), net transfers and Energy Efficiency treated as a resource. The PJM RTO Reserve Requirement is 15.6 percent for the 2012/2013 planning period, which runs from June 1, 2012 through May 31, 2013. For more information see the 2011 PJM Reserve Requirement Study¹⁷.

The Reliability Pricing Model (RPM) or forward Capacity Market provides:

Procurement of capacity three years before it is needed through a competitive auction;

- Locational pricing for capacity that reflects limitations on the transmission system's ability to deliver electricity into an area and to account for the differing need for capacity in various areas of PJM;
- A variable resource requirement to help set the price for capacity;

- A backstop mechanism to ensure that sufficient resources will be available to preserve system reliability.

PJM RTO will have an adequate Reserve Margin through the 2012 Summer Peak Period.

The difference between the PJM RTO Reserve Margin and the PJM RTO Reserve requirement is 9.8 percent or over 15,000 MW. The highly unlikely loss of a similar amount of generation due to retirements or forced outages would task the PJM operators to find replacement resources. An extremely hot and humid summer could push load up but the probability of this occurring has been included in our Reserve Requirement studies.

3. Demand

The PJM RTO 2011 summer peak was 163,762 MW which occurred on July 21, 2011 hour ending 17. This was the PJM RTO's All Time Peak. On a weather-normalized basis, the PJM RTO 2011 summer peak forecast was 154,383 MW. The difference can be attributed to a very hot summer in most of the PJM region. Several consecutive days were well above 100 degrees, which is rather unusual for the PJM region.

The forecast for the 2012 PJM RTO summer peak is 153,782 MW. The combination of the new economic driver and a downward revision to the economic outlook for the PJM area has resulted in lower peak and energy forecasts compared to the same year in last year's report. This year's forecast reflects PJM's adoption of an independent consultant's recommendation to replace the load model's previous economic driver (Gross Metropolitan Product) with a variable that incorporates six economic measures (Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment).

This year's report includes the load of Duke Energy Ohio/Kentucky (DEOK), which was integrated into the PJM RTO on January 1, 2012.

A downward revision to the near-term economic outlook for both the U.S. and PJM area resulted in lower peak and energy forecasts in the 2012 load forecast compared to the 2011 load forecast. This is tied to revised assumptions regarding the timing of the recovery of the U.S. economy. While growth in later years accelerates, the economy is unable to make up the shortfall until after 2022.

This year's forecast reflects PJM's adoption of an independent consultant's recommendation to replace the load model's previous economic driver (Gross Metropolitan Product) with a variable that incorporates six economic measures (Gross

¹⁷ http://www.pjm.com/planning/resource-adequacy-planning/~/_media/planning/res-adeq/2011-rrs-study.ashx

Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment).

4. Demand-Side Management

Acceptance of Demand Side Management resources will continue to the end of May 2012. Approximately 4,000 MW has been accepted already and the number grows every day. Last year we had 11,600 MW of Demand Side resources available during the summer peak period. We expect similar amounts this year and are using last year's actual DSM as this year's forecast. The total amount of Energy Efficiency for the PJM area that is expected to be available on peak for Summer 2012 is 581 MW.

Demand side resources can be of three different types in PJM. Accepted through the forward capacity market (Reliability Pricing Model - RPM), is DSM that is dispatched like generator resources. Also the more typical type of Demand side resource is the kind that is retained for use by the PJM operators during capacity emergencies. The third type of demand side resource is DSM used as reserves accepted through the Ancillary Service Market.

Energy Efficiency programs included in the 2012 load forecast are impacts approved for use in the PJM Reliability Pricing Model (RPM). Measurement and verification of energy efficiency programs are governed by rules specified in PJM Manual 18B. To demonstrate the value of an energy efficiency resource, resource providers must comply with the measurement and verification standards defined in this manual by establishing M&V plans, providing post-installation M&V reports, and undergoing an M&V audit.

Acceptance of Demand Side Management resources will continue to the end of May 2012. Approximately 4,000 MW has been accepted already and the number grows every day. Last year we had 11,600 MW of Demand Side resources available during the summer peak period. We expect similar amounts this year and are using last year's actual DSM as this year's forecast. The total amount of Energy Efficiency for the PJM area that is expected to be available on peak for Summer 2012 is 581 MW. DSM used for reserves is limited by the RFC standard BAL-002-RFC-02 to 25 percent of the Operating Reserve requirement. This type of DSM is typically fully subscribed and can range up to approximately 2,500 MW during a peak summer day.

5. Generation

The predominant source of fuel in PJM is coal at approximately 42 percent. Next is natural gas at 26 percent and nuclear at 18 percent.

No capacity resource changes are expected through the summer of 2012. All Capacity changes in PJM occur only on June 1 of each year.

PJM had an increase of 5,007 MW since last summer almost completely due to the addition of DEOK generation. Generation additions and retirements in the rest of PJM almost netted out. A new natural gas combined cycle unit at Dresden was added at 545 MW. Kearny natural gas units 13 and 14 were added for 267 MW. A new natural gas combined cycle unit named Virginia City was added in AEP for 585 MW. Martins Creek 4 oil unit was uprated 70 MW in PPL. Susquehanna nuclear units 1 and 2 in PPL were uprated 90 MW. A net of 568 MW of uprates and derates also occurred. Benning 15 and 16 totaling 548 MW of oil generation were retired in BGE. Gorsuch units 1-4 totaling 189 MW of coal generation were retired in AEP. The Buzzard Point East and West oil CTs totaling 210 MW were retired in Pepco. The Hudson 1 natural gas unit at 322 MW was retired in PSE&G. Also in PSE&G the Kearny 10 and 11 natural gas units were retired for a loss of 250 MW. The State Line 3 and 4 units were totaling 515 MW retired from ComEd. No units were brought back into service since the last assessment.

PJM has no on-going long-term outages of generation. Behind-the-meter generation is not considered as capacity in PJM. It offsets load that is also behind the meter.

The Laurel Mountain Energy Storage Facility consists of 8 “Smart Grid Stabilization System” Lithium Ion battery modules for a total output of 27.4 MW on the same site as the Laurel Mountain Wind Farm and is located at Laurel Mountain, West Virginia. 2 MW (300 kilowatt hours of storage) battery for frequency regulation has been installed on the same property as the Paradise Solar project in Deptford, New Jersey.

PJM does not anticipate any reliability concerns resulting from minimum demand and over generation. Intermittent resources can be required to disconnect. Established procedures ensure reliability concerns resulting from overgeneration are addressed.

6. On-Peak Capacity Transactions

All transactions are firm for both specific generation and transmission. Firm contacts are mostly long-term but some are shorter in the one to three year time-frames. All the transactions are firm through this summer's peak period. PJM has no reliance on outside assistance for emergency imports. There is no emergency generation needed to be available to meet PJM Reserve Margin Requirement.

7. Transmission

Since the beginning of the last winter peak season, the following facilities have come on-line:

- Chase City-Clarksville 115 kV line in Dominion
- Brookside-Reedsburg-Longview 138 kV line in ATSI

It is anticipated that the following facilities will go in service before the 2012 summer peak period

- Fredricksburg-Possum Point 230 kV line will get tapped to Garrisonville in Dominion
- Remington-Sowego will be converted from 115 kV to 230 kV in Dominion
- A second Doods-Dupont-Waynesboro 115 kV line in Dominion
- Yorktown-Hayes 230 kV in Dominion
- Indian River-Bishop 138 kV line in Delmarva

It is anticipated that the following facilities will go in service during the 2012 summer peak period:

- A second Whiteley-Franklin 138 kV line will be added in AP
- The Galion-GM Mansfield-Longview 138 kV line will be reconfigured to bypass GM Mansfield in ATSI
- Two Perryman-Harford 115 kV lines in BG&E
- Hopewell-Bull Hill 230 kV line in Dominion
- Two new Ritchie-Benning Station "A" 230 kV lines in Pepco

The Linden 230 kV PAR was replaced. No other substation equipment is expected to be added during this summer.

There are no project delays or temporary service outages for transmission facilities (lines or transformers) that will impact reliability during the summer. No new transmission projects are needed to go in service during this summer to maintain reliability.

8. Operations

The PJM Operations Analysis Task Force (OATF) summer assessment did not identify any reliability issues. The OATF does anticipate redispatch and switching procedures to control local thermal and voltage violations in some transmission zones. No special operating procedures are required from integration of variable resources. PJM has developed a Wind Power Forecast tool and visualization to assist operations. PJM has integrated Wind into its automated dispatch systems. PJM does not anticipate any reliability concerns resulting from minimum demand and over generation. Intermittent

resources can be required to disconnect. Established procedures ensure reliability concerns resulting from overgeneration are addressed.

There are some minor concerns related to the amount of information available to PJM which can be used to determine the amount of DR to dispatch during emergency conditions. PJM has filed tariff changes with FERC that will require more robust reporting of the DR operational capability in real time for Curtailment Service Providers. PJM does not have a reliability concerns but the additional information will help avoid the dispatch of DR that may not be necessary to meet the need of the emergency conditions. PJM has addressed the issue of availability by creating 3 different DR products: Limited DR (10 days for 6 hours per day), Extended Summer DR (unlimited days during summers for 10 hours per day) and Annual DR (unlimited days for 10 hours per day) and requiring the necessary amount of annual capacity (DR or generation) to fulfill the PJM reliability requirements.

PJM requires Generation Owners to place resources into the "Maximum Emergency Category" if environmental restrictions limit run hours below pre-determined levels. Max Emergency units are the last to be dispatched.

No other unusual operating conditions that could significantly impact reliability for the upcoming summer are anticipated.

9. Vulnerability Assessment

PJM has very little hydro generation and reservoir levels are adequate. PJM expects no problems with warm cooling water. Any one specific generator outage, even if it is long-term, can be replaced with other resources available within PJM. Demand side resources are not of a significant enough size to be of great concern for unresponsiveness. Penalties exist to make unresponsiveness financially unattractive. No special operating procedures required. PJM has developed a Wind Power Forecast tool and visualization to assist operations. No other PJM specific issues exist.

The Richland 138 kV substation will be reconfigured to permit the removal of the Richland SPS. No new SPS were added.

PJM is assessing the impacts of the CSAPR (Cross State Pollution Rule), MATS (Mercury Air and Toxics Standards) and also state level environmental rules like NJ HEDD (High Electricity Demand Day) on resource adequacy, transmission planning and ancillary services for the PJM footprint. PJM developed an analysis of coal generation at risk of retiring based on an assessment of required environmental retrofit costs vs. the cost of constructing a new natural gas-fired turbine. This at risk generation analysis concluded that there is no overall resource adequacy concern for the PJM footprint, however there may be localized reliability concerns that will need to be addressed either with replacement generation capacity or transmission upgrades if the impacted units are retired or need lengthy environmental retrofit outages. PJM continues to coordinate

closely with PJM Generation Owners, PJM Transmission Owners and neighboring systems through the PJM Committee structure and consistent with the PJM Tariff and manuals. In order to maintain system reliability, PJM will designate units as "Reliability Must Run" if their retirement date is targeted to be in advance of required system reinforcements.

PJM requested that all impacted generation owners provide the most accurate information regarding unit retirements, environmental retrofits, unit derates and potential regulatory issues related to the environmental regulations. Combined with the publically announced unit retirements and the deactivation analysis results, PJM is utilizing this information to address short term impacts and long term projections through 2018. PJM is communicating with interconnected Transmission Owners as required to address local reliability issues, and also communicating with MISO to compare reliability analyses and coordinate outages.

At this point PJM has added the environmental retrofit outages, to the extent provided by the generation owners, to projections for maintenance outages from 2012-2018, and we are continuing to assess the impact to off-peak reliability. PJM will continue to coordinate closely to analyze the impact of retiring generation, planned outage to perform retrofits, normal generation and transmission maintenance outages as well as transmission outages required to perform planning upgrades to resulting from retiring generation.

Generation owners have indicated that while at this time there appears to be sufficient time to complete environmental retrofits, if there are delays in scheduling retrofit outages due to system constraint issues or capital budget limitations, then there may be significant challenges in completing the retrofit outages in the required time to comply with environmental regulations.

Yes there are currently generators performing environmental retrofit work during the current Spring 2012 maintenance period.

PJM has established rules/procedures to ensure fuel is conserved to maintain an adequate level on-site fuel supplies under forecasted peak load conditions. PJM coordinates with neighboring entities and gas pipelines to quickly address fuel issues. No fuel supply issues are anticipated. No fuel transportation issues are anticipated.

Assessment Methodology

1. Planning Reserve Margins

PJM has adopted a Loss of Load Expectation (LOLE) standard of one occurrence in ten years. PJM performs an annual LOLE study to determine the reserve margin required to satisfy this criterion. The study recognizes, among other factors, load forecast uncertainty due to both economics and weather, generator unavailability, deliverability of resources to load, and the benefit of interconnection with neighboring systems. The methods and modeling assumptions used in this study are available in PJM Manual 20¹⁸

Since PJM is summer-peaking, the coincident 50/50 summer peaks are used in resource adequacy evaluations.

Resources accepted by the PJM Forward Capacity Market for the current year.

PJM's forward capacity market (RPM) requires that units are committed three years in the future. As new units are accepted into the Capacity totals, they are considered Future-Planned for future years. For the period beyond the three-year Capacity market timeframe, projects in the PJM Generation queues with signed Interconnection Service Agreements are also considered Future-Planned.

The remaining generation in the PJM Generation Interconnection Queues is considered Conceptual and is not considered in our Reserve Margin calculation.

Energy-Only units only participate in our Energy Market. They are not considered in our Reserve Margin calculation.

Some PJM Energy-Only units are Transmission-Limited resources and only participate in our Energy Market. They are not considered in our Reserve Margin calculation.

Demand side resources accepted through the forward capacity market is DSM that is dispatched like generator resources and is treated as such. The more typical type of Demand side resource is the kind that is retained for use by the PJM operators during capacity emergencies and reduces load.

Behind-the-meter generation is not considered at all in PJM Reserve Margin calculations

External imports are fully counted in Reserve Margin studies if the transfer is firm for both generation and transmission.

As PJM is summer-peaking, the coincident 50/50 summer peaks are used in resource adequacy evaluations.

¹⁸ <http://www.pjm.com/documents/~media/documents/manuals/m20.ashx>

The PJM Reserve Requirement has remained relatively unchanged for the last several years; varying by 0.1 percentage points. This change can be attributed to varying forced outage rates.

PJM has no subregions.

2. Demand

The PJM Load forecasting methodology is in PJM Manual 19¹⁹

As PJM is summer-peaking, the coincident 50/50 summer peaks are used in resource adequacy evaluations.

3. Demand-Side Management

Energy Efficiency programs included in the load forecast are impacts approved for use in the PJM Reliability Pricing Model (RPM). Measurement and verification of energy efficiency programs are governed by rules specified in PJM Manual 18B. To demonstrate the value of an energy efficiency resource, resource providers must comply with the measurement and verification standards defined in this manual by establishing M&V plans, providing post-installation M&V reports, and undergoing an M&V audit. PJM does not track Conservation. Participants submit load data from the EDC meters used for retail service or from meters meeting PJM's standards. See PJM Manual 11, Section 10.6²⁰. Participants can be audited.

4. Generation

Distributed generation accepted in the PJM forward capacity Market is treated just like any other generator. Behind-the-meter generation is not accounted for in PJM.

Existing-Certain are units that have been accepted in PJM's forward capacity market for the current year. Existing-Other is used to account the portion of variable units not accepted a PJM Capacity. Existing-Inoperable is not used in PJM at this time.

PJM's forward capacity market (RPM) requires that units are committed three years in the future. As new units are accepted into the Capacity totals, they are considered Future-Planned for future years. For the period beyond the three-year Capacity market timeframe, projects in the PJM Generation queues with signed Interconnection Service Agreements are also considered Future-Planned. Future-Other is used to account the portion of variable units not accepted a PJM Capacity.

¹⁹ <http://www.pjm.com/~media/documents/manuals/m19.ashx>

²⁰ <http://www.pjm.com/~media/documents/manuals/m11.ashx>

Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially utilize class average capacity factors which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation only historic performance over the peak period is used to determine the individual unit's capacity factor.

There are no enhancements to how expected on-peak capacity values are calculated in PJM.

5. On-Peak Capacity Transactions

All transactions are firm for both generation and transmission. Transactions are not firm for both generation and transmission are not included in a reliability assessment. No imports or exports are based on partial path reservations. No import or export contracts are Liquidated Damage Contracts.

There are no capacity transaction details that are unique to PJM.

6. Transmission

Outages of both generation and transmission are studied at various operational time horizons: seasonal, weekly and daily. Operations Planning can shuffle around planned outages to take into account forced outages and abnormal weather. Section 4 of PJM Manual 3²¹ describes the outage planning process.

PJM has developed Reactive Transfer Interfaces to ensure sufficient dynamic MVAR reserve in load centers that rely on economic imports to serve load. PJM day-ahead and real-time Security Analysis ensure sufficient generation is scheduled / committed to control pre-/post-contingency voltages and voltage drop criteria within acceptable predetermined limits as outlined in M-3, section 3.

There are no other transmission issues unique to PJM.

The 2011 PJM Regional Transmission Expansion Plan²² report was issued on February 28, 2011.

²¹ <http://www.pjm.com/~media/documents/manuals/m03.ashx>

²² <http://www.pjm.com/documents/reports/rtep-report.aspx>

8. CP-8 2012 Summer Multi-Area Probabilistic Reliability Assessment

EXECUTIVE SUMMARY

Introduction

This study assessed NPCC Area reliability by estimating the projected use of Area Operating Procedures designed to mitigate resource shortages for the summer of 2012 (May through September). The CP-8 Working Group closely coordinated its efforts with those of the CO-12 Working Group's study, "*NPCC Reliability Assessment for Summer 2012*", April 2012.²³

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

Base Case Results

For the May - September 2012 period, assuming the Base Case conditions, Figures EX-1a and EX-1 b show there would be no significant likelihood of implementing operating procedures in response to a capacity deficiency for both the expected and extreme load forecasts. The expected load forecast is based upon the probability-weighted average of the seven load levels simulated; the extreme load represents the second highest of the seven load levels, having approximately a 6% chance of occurring.

²³ See: <http://www.npcc.org/seasonal.asp?Folder=CurrentYear>

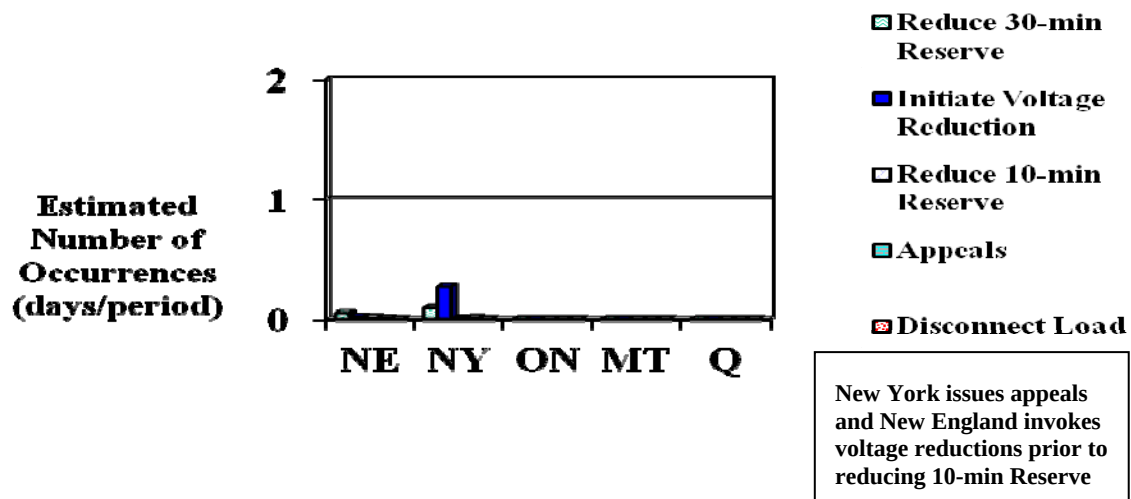


Figure EX-1a

Expected Use of Indicated Operating Procedures for Summer 2012

Considering Base Case Assumptions (May – September)

(Expected Load Forecast)

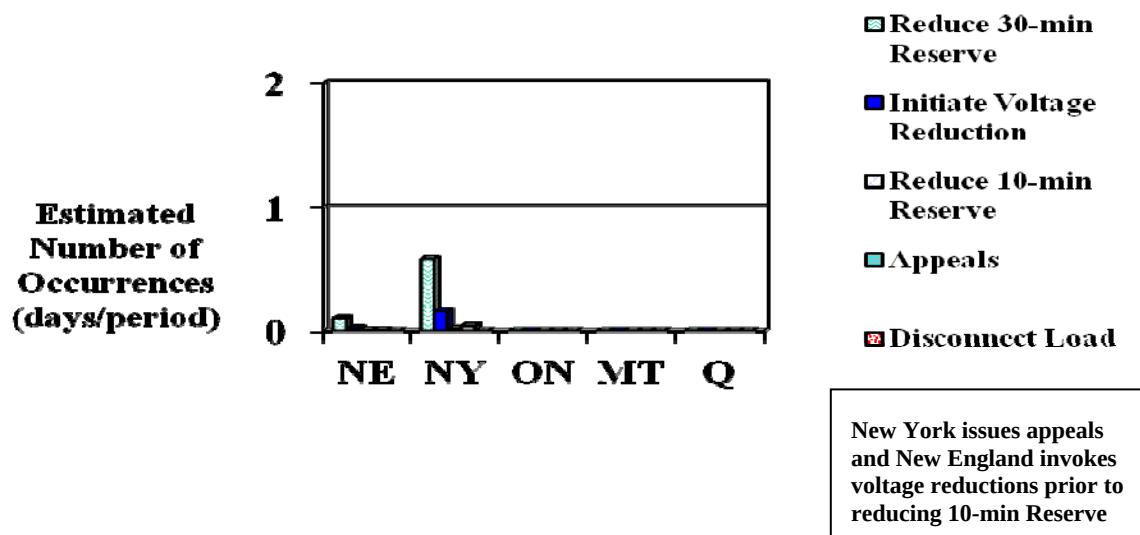


Figure EX-1b

Expected Use of Indicated Operating Procedures for Summer 2012

Considering Base Case Assumptions (May – September)

(Extreme Load Forecast)

Severe Case Results

For the May - September 2012 period, Figure EX-1c shows the expected use of the indicated operating procedures assuming the Severe Case conditions and the expected load forecast.

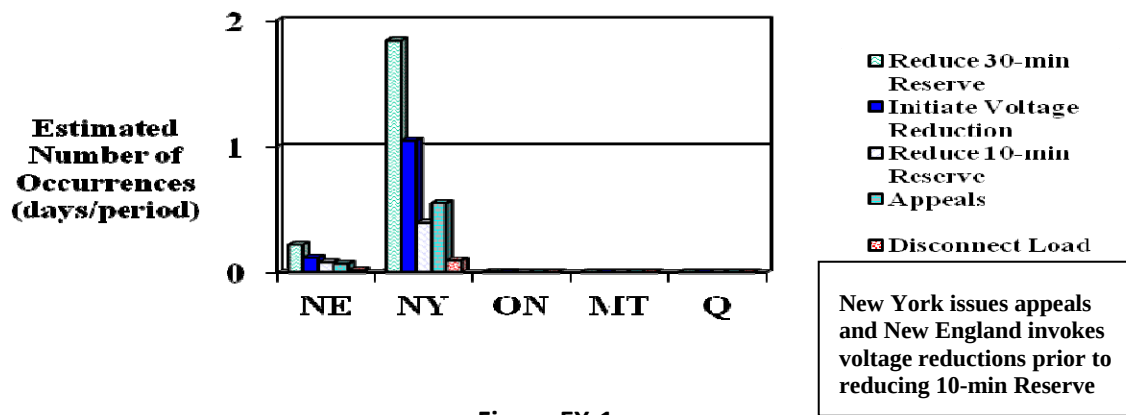


Figure EX-1c

Expected Use of Indicated Operating Procedures for Summer 2012

Considering Severe Case Assumptions (May – September)

(Expected Load Forecast)

For the May - September 2012 period, Figure EX-1d shows the expected use of the indicated operating procedures assuming the Severe Case conditions and the extreme load forecast.

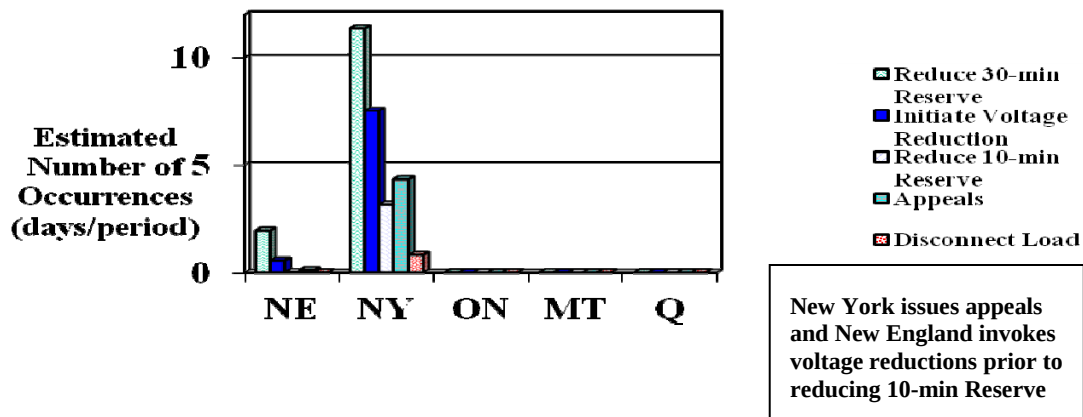


Figure EX-1d

Expected Use of Indicated Operating Procedures for Summer 2012

Considering Severe Case Assumptions (May – September)

(Extreme Load Forecast)

Conclusions

Use of operating procedures designed to mitigate resource shortages (reducing 30-minute reserve, voltage reduction, and reducing 10-minute reserve) is not expected during the 2012 summer period for the Base Case conditions assumed for the expected and extreme load forecast assumptions. Slower economic growth than anticipated, coupled with the continuing impacts of conservation initiatives has resulted in a lower overall NPCC demand forecast compared to last year. Furthermore, new resources and transmission capacity resulting from transmission projects planned to be available this summer are additional factors that act to minimize the expected need for the use of these operating procedures in 2012.

Figures EX-1c (expected load level) and EX-1d (extreme load level), show the possible range of operating procedure use if reductions in anticipated resources, delays of expected transmission projects and/or additional constraints materialize coincident with higher than expected loads (such as caused by a wide spread, prolonged heat wave with high humidity and near record temperatures).

Appendix I – Summer 2012 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	Interruptible Load MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin ³ MW	Bottled Resources MW	Revised Net Margin ⁴ MW
29-Apr-12	160,056	304.7	0	160,361	82,903	4,578	35,331	7,773	7,717	31,215	429	30,786
6-May-12	160,056	304.7	0	160,361	83,734	4,592	33,164	7,978	7,734	32,343	1,419	30,925
13-May-12	160,056	304.7	0	160,361	85,600	4,599	31,871	7,798	7,745	31,946	2,189	29,758
20-May-12	160,056	304.7	0	160,361	92,529	4,604	27,247	7,885	7,861	29,443	3,191	26,252
27-May-12	160,056	304.7	0	160,361	92,379	4,591	24,231	7,665	7,949	32,729	3,519	29,209
3-Jun-12	157,234	304.7	0	157,539	99,949	4,639	23,967	7,670	7,357	23,234	3,249	19,985
10-Jun-12	157,234	304.7	0	157,539	101,381	4,611	22,946	7,718	7,361	22,743	3,202	19,542
17-Jun-12	157,242	304.7	0	157,547	104,027	4,604	22,212	7,783	7,361	20,768	3,381	17,388
24-Jun-12	157,242	304.7	0	157,547	104,724	4,602	22,242	7,886	7,361	19,936	3,341	16,595
1-Jul-12	158,052	304.7	0	158,357	105,405	4,596	22,254	7,844	6,661	20,789	3,516	17,272
8-Jul-12	158,052	304.7	0	158,357	107,052	4,597	21,689	7,975	6,661	19,576	3,754	15,822
15-Jul-12	158,052	304.7	0	158,357	106,946	4,596	21,154	7,893	6,661	20,299	4,489	15,810
22-Jul-12	158,052	304.7	0	158,357	105,979	4,629	19,227	7,971	6,661	23,147	6,164	16,983
29-Jul-12	158,052	304.7	0	158,357	106,148	4,598	19,886	8,097	6,661	22,162	5,246	16,916
5-Aug-12	158,084	304.7	0	158,389	106,499	4,618	19,347	8,456	6,661	22,044	4,482	17,562
12-Aug-12	158,084	304.7	0	158,389	106,399	4,621	20,194	8,434	6,661	21,322	4,044	17,278
19-Aug-12	158,084	304.7	0	158,389	105,912	4,635	20,902	8,315	6,661	21,234	3,527	17,707
26-Aug-12	158,084	304.7	0	158,389	105,658	4,631	20,589	8,394	6,661	21,718	3,996	17,722
2-Sep-12	158,035	304.7	0	158,340	89,464	4,664	22,945	8,167	6,625	35,803	5,459	30,344
9-Sep-12	158,035	304.7	0	158,340	90,091	4,608	23,799	8,204	6,626	34,229	4,933	29,296
16-Sep-12	158,035	304.7	0	158,340	88,605	4,633	25,625	7,957	6,576	34,210	5,652	28,558
23-Sep-12	158,035	304.7	0	158,340	85,753	4,635	26,887	7,829	6,565	35,941	5,471	30,471

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 Outages
- 4) Revised Net Margin = Net Margin - Bottled resources
Maritimes and Québec Reliability Coordinator areas are winter peaking systems and expect to be able to provide assistance to other areas when needed up to the transfer capability of the interconnections. However, Maritimes and Québec net margins exceed transfer capability to other NPCC areas throughout the Summer Operating Period. This is captured as Bottled resources in this table.

Table AP-2 – Maritimes

Week Beginning Sundays	Installed Capacity MW	Firm Purchases MW	Firm Sales MW	Total Capacity MW	Load Forecast MW	Interruptible Load MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW
29-Apr-12	7,725	0	0	7,725	3,724	212	2,041	628	273	1,271
06-May-12	7,725	0	0	7,725	3,536	227	2,087	628	273	1,428
13-May-12	7,725	0	0	7,725	3,549	234	2,481	628	273	1,028
20-May-12	7,725	0	0	7,725	3,460	238	2,464	628	273	1,138
27-May-12	7,725	0	0	7,725	3,366	225	2,597	628	273	1,086
03-Jun-12	7,426	0	0	7,426	3,315	250	2,646	628	272	815
10-Jun-12	7,426	0	0	7,426	3,102	222	2,838	628	272	808
17-Jun-12	7,426	0	0	7,426	3,058	215	2,930	628	272	753
24-Jun-12	7,426	0	0	7,426	3,076	213	2,930	628	272	734
01-Jul-12	7,457	0	0	7,457	2,999	207	2,667	628	272	1,098
08-Jul-12	7,457	0	0	7,457	3,182	208	2,734	628	272	850
15-Jul-12	7,457	0	0	7,457	3,181	207	2,685	628	272	899
22-Jul-12	7,457	0	0	7,457	3,211	241	2,148	628	272	1,439
29-Jul-12	7,457	0	0	7,457	3,142	209	2,300	628	272	1,324
05-Aug-12	7,457	0	0	7,457	3,151	229	2,005	891	272	1,367
12-Aug-12	7,457	0	0	7,457	3,114	232	1,897	891	272	1,516
19-Aug-12	7,457	0	0	7,457	3,142	246	2,127	891	272	1,271
26-Aug-12	7,457	0	0	7,457	3,182	242	2,064	891	272	1,291
02-Sep-12	7,457	0	0	7,457	3,275	275	2,124	891	272	1,170
09-Sep-12	7,457	0	0	7,457	3,101	219	2,036	891	272	1,377
16-Sep-12	7,457	0	0	7,457	3,150	244	2,037	891	272	1,351
23-Sep-12	7,457	0	0	7,457	3,177	247	2,139	891	272	1,225

Notes

Table AP-3 – New England

Week Beginning Sundays	Installed Capacity MW	Firm Purchases MW	Firm Sales MW	Total Capacity MW	Load Forecast MW	Interruptible Load MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW
29-Apr-12	34,485	505	100	34,890	16,733	1,104	5,447	2,000	3,400	8,414
06-May-12	34,485	505	100	34,890	19,957	1,104	3,686	2,000	3,400	6,951
13-May-12	34,485	505	100	34,890	20,920	1,104	2,635	2,000	3,400	7,039
20-May-12	34,485	505	100	34,890	21,815	1,104	1,490	2,000	3,400	7,289
27-May-12	34,485	505	100	34,890	22,797	1,104	142	2,000	3,400	7,655
03-Jun-12	31,962	776	100	32,638	23,455	1,127	152	2,000	2,800	5,358
10-Jun-12	31,962	776	100	32,638	24,080	1,127	146	2,000	2,800	4,739
17-Jun-12	31,969	776	100	32,645	24,876	1,127	165	2,000	2,800	3,932
24-Jun-12	31,969	776	100	32,645	25,192	1,127	145	2,000	2,800	3,636
01-Jul-12	31,969	776	100	32,645	25,889	1,127	142	2,000	2,100	3,642
08-Jul-12	31,969	776	100	32,645	26,462	1,127	188	2,000	2,100	3,023
15-Jul-12	31,969	776	100	32,645	26,462	1,127	177	2,000	2,100	3,034
22-Jul-12	31,969	776	100	32,645	26,462	1,127	185	2,000	2,100	3,026
29-Jul-12	31,969	776	100	32,645	26,462	1,127	172	2,000	2,100	3,039
05-Aug-12	31,969	776	100	32,645	26,462	1,127	144	2,000	2,100	3,067
12-Aug-12	31,969	776	100	32,645	26,462	1,127	150	2,000	2,100	3,061
19-Aug-12	31,969	776	100	32,645	26,462	1,127	152	2,000	2,100	3,059
26-Aug-12	31,969	776	100	32,645	26,462	1,127	166	2,000	2,100	3,045
02-Sep-12	31,969	776	100	32,645	24,256	1,127	196	2,000	2,100	5,221
09-Sep-12	31,969	776	100	32,645	22,892	1,127	290	2,000	2,100	6,491
16-Sep-12	31,969	776	100	32,645	22,530	1,127	1,892	2,000	2,100	5,251
23-Sep-12	31,969	776	100	32,645	22,439	1,127	2,729	2,000	2,100	4,505

Notes

- Installed Capacity is based on Seasonal Claimed Capabilities as of 3/1/12, plus future capacity additions. Firm Purchases and Sales and Interruptible Load are based on ISO-NE Forward Capacity Market (FCM) resource obligations for the 2011-2012 (though May 31st) and 2012-2013 (beginning June 1st) capacity commitment periods.
- Prior to June 1st, purchases and sales consist of 296 MW of imports from Québec and 209 MW from New York, and an export of 100 MW to New York. Beginning on June 1st, imports are 465 MW from Québec and 311 MW from New York, and an export of 100 MW to New York.
- Load Forecast assumes Peak Load Exposure to be reported in the 2012 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 February 15, 2012.
- Assumed unplanned outages based on historical observation of outages.

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
29-Apr-12	39,583	221	0	39,804	21,958	1,936	8,326	1,950	1,494	8,013
06-May-12	39,583	221	0	39,804	20,179	1,936	7,987	1,950	1,511	10,113
13-May-12	39,583	221	0	39,804	22,049	1,936	7,769	1,950	1,522	8,451
20-May-12	39,583	221	0	39,804	27,652	1,936	5,441	1,950	1,638	5,060
27-May-12	39,583	221	0	39,804	26,768	1,936	3,684	1,950	1,726	7,613
03-Jun-12	39,583	221	0	39,804	33,295	1,936	3,495	1,950	1,735	1,266
10-Jun-12	39,583	221	0	39,804	33,295	1,936	3,420	1,950	1,739	1,337
17-Jun-12	39,583	221	0	39,804	33,295	1,936	3,425	1,950	1,739	1,332
24-Jun-12	39,583	221	0	39,804	33,295	1,936	3,420	1,950	1,739	1,337
01-Jul-12	39,583	221	0	39,804	33,295	1,936	3,420	1,950	1,739	1,337
8-Jul-12	39,583	221	0	39,804	33,295	1,936	3,420	1,950	1,739	1,337
15-Jul-12	39,583	221	0	39,804	33,295	1,936	3,420	1,950	1,739	1,337
22-Jul-12	39,583	221	0	39,804	33,295	1,936	3,420	1,950	1,739	1,337
29-Jul-12	39,583	221	0	39,804	33,295	1,936	3,420	1,950	1,739	1,337
05-Aug-12	39,583	221	0	39,804	33,295	1,936	3,420	1,950	1,739	1,337
12-Aug-12	39,583	221	0	39,804	33,295	1,936	3,420	1,950	1,739	1,337
19-Aug-12	39,583	221	0	39,804	33,295	1,936	3,420	1,950	1,739	1,337
26-Aug-12	39,583	221	0	39,804	33,295	1,936	3,420	1,950	1,739	1,337
02-Sep-12	39,583	221	0	39,804	21,032	1,936	4,149	1,950	1,703	12,907
09-Sep-12	39,583	221	0	39,804	24,715	1,936	4,131	1,950	1,704	9,241
16-Sep-12	39,583	221	0	39,804	23,228	1,936	5,133	1,950	1,654	9,776
23-Sep-12	39,583	221	0	39,804	20,023	1,936	5,339	1,950	1,643	12,785

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	Installed	Firm	Firm	Total	Load	Interruptible	Known Maint./	Req.	Unplanned	Net
Beginning	Capacity	Purchases	Sales	Capacity	Forecast	Load	Derat./Bottled	Operating	Outages	Margin
Sundays	MW	MW	MW	MW	MW	MW	Cap. MW	Reserve MW	MW	MW
29-Apr-12	35,436	0	0	35,436	17,378	1,326	9,098	1,402	1,350	7,534
06-May-12	35,436	0	0	35,436	17,862	1,326	9,113	1,402	1,350	7,035
13-May-12	35,436	0	0	35,436	17,856	1,326	8,567	1,547	1,350	7,442
20-May-12	35,436	0	0	35,436	19,015	1,326	7,772	1,547	1,350	7,078
27-May-12	35,436	0	0	35,436	19,038	1,326	7,711	1,547	1,350	7,116
03-Jun-12	35,436	0	0	35,436	19,777	1,326	7,294	1,547	1,350	6,794
10-Jun-12	35,436	0	0	35,436	20,601	1,326	6,366	1,547	1,350	6,898
17-Jun-12	35,436	0	0	35,436	22,205	1,326	6,104	1,547	1,350	5,556
24-Jun-12	35,436	0	0	35,436	22,769	1,326	6,041	1,547	1,350	5,055
01-Jul-12	36,186	0	0	36,186	22,709	1,326	6,180	1,547	1,350	5,726
08-Jul-12	36,186	0	0	36,186	23,409	1,326	6,311	1,547	1,350	4,895
15-Jul-12	36,186	0	0	36,186	23,406	1,326	6,337	1,547	1,350	4,872
22-Jul-12	36,186	0	0	36,186	23,008	1,326	5,554	1,547	1,350	6,053
29-Jul-12	36,186	0	0	36,186	23,120	1,326	5,522	1,547	1,350	5,973
05-Aug-12	36,186	0	0	36,186	22,533	1,326	5,491	1,547	1,350	6,591
12-Aug-12	36,186	0	0	36,186	22,387	1,326	5,915	1,547	1,350	6,313
19-Aug-12	36,186	0	0	36,186	21,974	1,326	5,897	1,547	1,350	6,744
26-Aug-12	36,186	0	0	36,186	21,747	1,326	6,095	1,547	1,350	6,773
02-Sep-12	36,186	0	0	36,186	20,954	1,326	8,157	1,402	1,350	5,649
09-Sep-12	36,186	0	0	36,186	19,412	1,326	8,351	1,402	1,350	6,997
16-Sep-12	36,186	0	0	36,186	19,463	1,326	8,333	1,402	1,350	6,964
23-Sep-12	36,186	0	0	36,186	19,131	1,326	9,016	1,402	1,350	6,613

Notes

1. Installed Capacity includes all generation registered in the IESO-administered market.
2. Load Forecast represents the normal weather case, weekly 60-minute peaks.
3. Know Maint/Derat/Bottled Cap includes the planned outages, deratings, historic hydroelectric reductions such as allowances for capacity.
4. Unplanned Outages is based on the average amount of generation in forced outage during May, June, July, August, and September, from 1998 to 2001.

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	Unplanned Outages MW	Net Margin MW
29-Apr-12	42,827	0	991	41,836	23,110	0	10,419	1,793	1,200	5,314
6-May-12	42,827	0	991	41,836	22,200	0	10,291	1,998	1,200	6,147
13-May-12	42,827	0	991	41,836	21,227	0	10,419	1,673	1,200	7,317
20-May-12	42,827	0	991	41,836	20,587	0	10,080	1,760	1,200	8,209
27-May-12	42,827	0	991	41,836	20,410	0	10,097	1,540	1,200	8,589
3-Jun-12	42,827	0	1,204	41,623	20,108	0	10,380	1,545	1,200	8,390
10-Jun-12	42,827	0	1,204	41,623	20,303	0	10,177	1,593	1,200	8,350
17-Jun-12	42,827	0	1,204	41,623	20,593	0	9,588	1,658	1,200	8,584
24-Jun-12	42,827	0	1,204	41,623	20,393	0	9,706	1,761	1,200	8,563
1-Jul-12	42,856	0	1,204	41,652	20,513	0	9,846	1,719	1,200	8,374
8-Jul-12	42,856	0	1,204	41,652	20,705	0	9,037	1,850	1,200	8,860
15-Jul-12	42,856	0	1,204	41,652	20,602	0	8,536	1,768	1,200	9,546
22-Jul-12	42,856	0	1,204	41,652	20,004	0	7,921	1,846	1,200	10,681
29-Jul-12	42,856	0	1,204	41,652	20,130	0	8,472	1,972	1,200	9,878
5-Aug-12	42,888	0	1,204	41,684	21,058	0	8,287	2,068	1,200	9,071
12-Aug-12	42,888	0	1,204	41,684	21,142	0	8,812	2,046	1,200	8,484
19-Aug-12	42,888	0	1,204	41,684	21,039	0	9,306	1,927	1,200	8,212
26-Aug-12	42,888	0	1,204	41,684	20,973	0	8,844	2,006	1,200	8,661
2-Sep-12	42,839	0	1,204	41,635	19,947	0	8,319	1,924	1,200	10,245
9-Sep-12	42,839	0	1,204	41,635	19,971	0	8,991	1,961	1,200	9,512
16-Sep-12	42,839	0	1,204	41,635	20,234	0	8,230	1,714	1,200	10,257
23-Sep-12	42,839	0	1,204	41,635	20,983	0	7,664	1,586	1,200	10,202
Notes										
1)	Includes independant power producers, Alcan and available capacity of Churchill Falls at the New foundland - Québec border.									
3)	Sales to NY and NE									
4)	Expected weekly internal peak load plus 154 MW for Cornw all including losses.									

Table AP-7– Bottled Capacity in the Maritimes and Québec Areas

Existing Transactions before June 1		Existing Transactions after June 1	
<u>Path</u>	<u>MW</u>	<u>Path</u>	<u>MW</u>
Que. to Ont.		Que. to Ont.	
Que. to NY	620	Que. to NY	620
Que. to NE	310	Que. to NE	510
NB to NE	0	NB to NE	0
Total	930	Total	1,130

Assumed Transfer Capability at Peak 7,086 MW

Week Beginning Sundays	Quebec Margin	Maritimes Margin	Total Net Margin	Available Transfer Capability	Bottled NE Resources	Total Bottled Resources
29-Apr-12	5,314	1,271	6,585	6,156	0	429
6-May-12	6,147	1,428	7,575	6,156	0	1,419
13-May-12	7,317	1,028	8,345	6,156	0	2,189
20-May-12	8,209	1,138	9,347	6,156	0	3,191
27-May-12	8,589	1,086	9,675	6,156	0	3,519
3-Jun-12	8,390	815	9,205	5,956	0	3,249
10-Jun-12	8,350	808	9,158	5,956	0	3,202
17-Jun-12	8,584	753	9,337	5,956	0	3,381
24-Jun-12	8,563	734	9,297	5,956	0	3,341
1-Jul-12	8,374	1,098	9,472	5,956	0	3,516
8-Jul-12	8,860	850	9,710	5,956	0	3,754
15-Jul-12	9,546	899	10,445	5,956	0	4,489
22-Jul-12	10,681	1,439	12,120	5,956	0	6,164
29-Jul-12	9,878	1,324	11,202	5,956	0	5,246
5-Aug-12	9,071	1,367	10,438	5,956	0	4,482
12-Aug-12	8,484	1,516	10,000	5,956	0	4,044
19-Aug-12	8,212	1,271	9,483	5,956	0	3,527
26-Aug-12	8,661	1,291	9,952	5,956	0	3,996
2-Sep-12	10,245	1,170	11,415	5,956	0	5,459
9-Sep-12	9,512	1,377	10,889	5,956	0	4,933
16-Sep-12	10,257	1,351	11,608	5,956	0	5,652
23-Sep-12	10,202	1,225	11,427	5,956	0	5,471

Appendix II – Load and Capacity Tables definitions

This appendix defines the terms used in the Load and Capacity tables of Appendix I. Individual Reliability Coordinator 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

In most cases, generator capabilities are based on the results of summer and winter audits. For those generators that are affected by ambient temperature, the audit results are adjusted to reflect output at 20 °F (-6.7 °C) during the winter and 90 °F (32 °C) during the summer. Daily cycle hydro capabilities are based on an analysis that takes into consideration historical stream flow.

The Qualified Capacity of intermittent resources is the average of the median net output during the summer peak demand hours over the past five years.

Québec

Both Hydro-Québec Production and Hydro-Québec Distribution provide capacity in Québec. For HQP, this includes its own generation, Churchill Falls, contracts with Rio Tinto Alcan and private producers (hydroelectric, wind, biomass, etc.). For HQD, this includes Independent Power Producers (TransCanada Energy, biomass, small hydro and wind generation).

The Installed Capacity corresponds to the *Total Internal Capacity* (Line 6) of the NERC ERO-2012SA Schedule 3A –Demand and Capacity, in the NERC 2012 Summer Reliability Assessment.

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

Installed capacity includes all the dispatchable, intermittent and self-scheduling generation registered with the IESO. A maximum net rating is used for each generator.

NPCC Glossary of Terms

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 capacity supply 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. The short term purchases may vary from year to year. Purchases correspond to the Firm Capacity transactions - Imports (Line 10a) of the NERC ERO-2012SA Schedule 3A – Demand and Capacity.

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

Only long-term, capacity-backed sales are included.

New York

NY does not use the firm transmission concept.

Québec

In this assessment, the 145 MW contract to Cornwall through Cedar Rapids Transmission is not included in the sales. It is included in the Québec Reliability Coordinator area demand. However, in the NERC Assessment ERO-2012S Schedule 3A it is included in the Firm Capacity transactions – Exports (Line 11a).

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)

Interruptible Load

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/Derates

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, deratings and generation bottling. It also includes wind generation deratings based on seasonal wind contribution factors.

Required Operating Reserve

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

NPCC Glossary of Terms

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.

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 hydraulic synchronous reserve distributed all over the system to be used as stability and frequency support reserve. The total reserve requirement varies with system configuration and transformer loading at large generation integration substations.

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 Load Forecast uncertainty, a provision for frequency regulation reserve and a provision for unplanned outages, based on historic conditions.

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 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. This is calculated in Table AP-7 of the Summer Assessment.

Revised net margin (NPCC Summary only)

Revised net margin = Net margin – Bottled resources

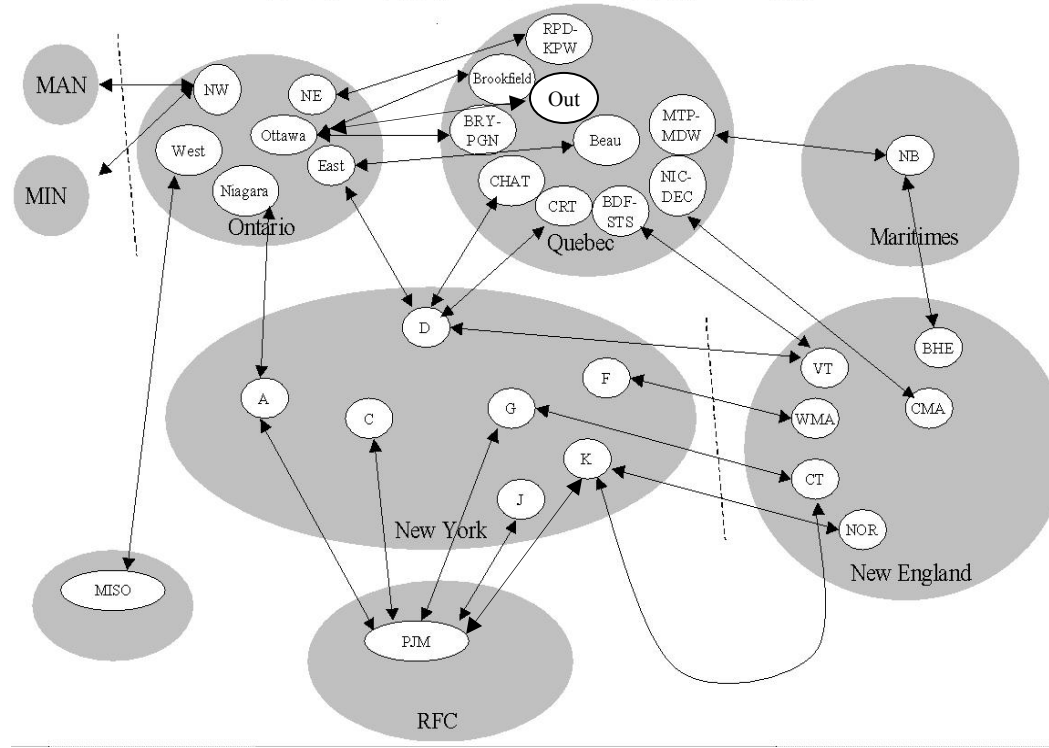
This is used only in the Summer Assessment and follows from the Bottled Resources calculation.

Appendix III – Summary of Normal and Expected Feasible Transfer Capability under Summer 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

Interconnection Points Between Areas



Reliability Coordinator area Acronym Description

Maritimes			NE	- North-East Sub-Area
NB	-	New Brunswick	Ottawa	- Ottawa
			East	- East
New England			RFC	- ReliabilityFirst Corporation
BHE	-	Bangor-Hydro Electric	MAN	- Manitoba
CMA	-	Central Massachusetts	MRO	- Midwest Reliability Organization
VT	-	Vermont	MIN	- Minnesota
WMA	-	Western Massachusetts	HAW	- Hawthorne
CT	-	Connecticut		
NOR	-	Norwalk	Québec	
			Brookfield	- Brookfield
			RPD-KPW	- Rapide-des-Iles/ Kipawa
			BRY-PGN	- Bryson - Pagan
New York			CHAT	- Chateauguay
The New York Balancing Authority area is divided into 11 zones (A – K) that are defined based on the transmission system topology.			CRT	- Cedar Rapids Transmission
			BDF-ST5	- Bedford/ Stanstead
Ontario			BEAU	- Beauharnois
NW	-	North West Sub-Area	NIC	- Nicolet
West	-	Western Sub-Area	MTP-MDW	- Matapedia-Madawaska
Niagara	-	Niagara	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	335	335	Eel River reduced by 15 MW due to losses
Lines 3012/3114 3113,	400	350	Madawaska HVdc derated to 350 MW due to temperature. (30 °C (86 °F))
Total	735	685	
New England			
NB / BHE	1,000	1,000	For resource adequacy studies, NE assumes that it can import 700 MW of capacity to meet New England loads. Note that New England would be able to import more than 700 MW if it backed down its generation in Maine or if many Maine generators were unavailable
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	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 525 MW but will increase it to 550 MW upon request from the NBSO under emergency operating conditions.
Total	550	550	
New York			
VT / D			
WMA / F			
CT / G			
NOR / K			
Sub Total	1,400	1,400	Feasible simultaneous transfer capability to New York excluding Cross Sound cable.
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	1,730	1,730	
Québec			
CMA / NIC-DEC HVDC link Phase II	1,700	1,700	Capability of the facility is 2,000 MW. Maximum import capability into Hydro-Québec's system at any one interconnection point (Maximum First Contingency Loss of Generation) in summer may vary from 2,000 MW during peak hours down to 1,000 MW during off-peak hours, with 1,700 MW being average during daytime hours.
Highgate (VT) – Bedford (BDF) Line 1429	170	0	Capability of facility is 220 MW. The DOE permit is 170 MW. There is no export capability from New England at peak demand.
Derby (VT) – Stanstead (STS) Line 1400	0	0	There is no capability to export to Québec through this interconnection.

Total	1,870	1,700	

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	1,400	1,400	Feasible Simultaneous Transfer to New England excluding Cross Sound Cable.
K / CT (CSC)	0	0	Cross Sound Cable power injection is up to 346 MW; losses reduce power at the point of withdrawal to 330 MW. The Cross Sound Cable is a DC tie and is not included in the Feasible Simultaneous Transfer capability with NY. The ability to transfer 330 MW from Long Island to New England is very dependent on local generation conditions. Under most conditions, no transfer is possible so the FTC is listed as 0 MW.
Total	1,400	1,400	
Ontario			
D / East Lines L33P, L34P			
A / Niagara Lines PA301, PA302, BP76, PA27			Simultaneous transfers between New York and Ontario may be impacted by loop flows assuming phase shifting capability of the 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	1,520	1,520	
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	Through Variable Frequency Transformer (VFT) at Langlois Substation, Québec.
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	1,660	1,660	
Total	1,960	1,960	Simultaneous Transfers between NY and Ontario 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	1,870	1,870	
Total	1,870	1,870	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 summer is 95 MW.
Ottawa / BRY – PGN Lines X2Y, P33C, Q4C	120	32	Circuit Q4C is capable of transferring 120 MW less ½ of Chat Falls generation that is considered in the Québec Installed Capacity (120-88=32). 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 190 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	2,035	1,947	
MISO Manitoba, Minnesota			

NW / MAN Lines K21W, K22W	263	263	Summer rating
NW / MIN Line F3M	140	140	
Total	403	403	Feasible Simultaneous Transfer to MAPP.

Transfers from Québec to¹

Interconnection Point	NTC at Interconnection Points (MW)	FTC under Peak Conditions (MW)	Rationale for Constraint
Maritimes			
MTP-MDW / NB Lines 2101, 2102 (HQ)	350 + radial load	350 + radial load	Eel River HVDC summer rating is 335 MW plus available radial load transfers. (Radial load transfer amount is dependent on local loading and will be updated monthly: May - 47 MW, June – 39 MW, July – 36 MW, August – 37 MW, September – 40 MW. These values may be updated as required
Lines 3012/3114, 3113	391 + radial load	350 + radial load	Madawaska HVDC derated to 350 MW due to temperature. (30 °C (86 °F) plus available radial load transfers. (Radial load transfer amount is dependent on local loading and will be updated monthly: May – 123 MW, June – 108 MW, July - 114 MW, August – 115 MW, September – 126 MW. These values will be updated as required.
Total	741 + radial load	700 + radial load	
New England			
NIC-DEC / CMA HVDC link	2,000	1,400	Capability of the facility is 2,000 MW; At certain times, flows over this tie can be limited to 1,200MW in order to respect operating agreements regarding largest single loss of source.
Bedford (BDF) – Highgate (VT) Line 1429	225	225	
Stanstead (STS) – Derby (VT) Line 1400	35	35	While voltage limits allow 80 MW to be transferred, normally only 35 MW of load in New England is connected.
Total	2,260	1,660	
New York			
Chateauguay – D Line 7040	1,500	1,800	The 1,800 MW FTC is permitted only in real-time and under specific ideal conditions. The maximum energy sink in New York remains at 1,200 MW at all times.

CRT – D Lines CD11, CD22	199	199	The sum of the Cornwall, Ontario load of 145 MW tapped off CD11-CD22 circuits and of the transfer to NY via Dennison cannot exceed 325 MW, which is the C.R.T. system capacity.
Total	1,699	1,999	
Ontario			
Beau / East Lines B5D, B31L	790	790	
Brookfield – Ottawa Lines D5A, H9A	200	200	Only one of H9A or D5A can be in services 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.
RPD-KPW / NE Lines D4Z, H4Z	55	55	This represents Line D4Z capacity. There is no capacity to export to Ontario through Line H4Z.
BRY-PGN / Ottawa Lines X2Y, P33C, Q4C	496	431	Capability of line P33C is 270 MW at 30 °C (86 °F) and the X2Y capability is 65 MW. Although there is no capability to export to Ontario through line Q4C, the four Chats Falls units allocated to Québec can be connected to Ontario for a net transfer of 96 MW. .
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	2,791	2,726	

Note 1: These capabilities may not exactly correspond to other numbers posted in Hydro-Québec's Annual Reports or on TransÉnergie's website. Such numbers — usually corresponding to winter ratings — are maximum import/export capabilities available at any one time of the year. The present assessment focuses on summer conditions and these limits recognize transmission or generation constraints in both Québec and its neighbors for the 2012 Summer Operating Period.

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 / ONT Lines L4D, L51D, J5D, B3N	1,580	1,580	
Total	1,580	1,580	Simultaneous Transfers between Michigan and Ontario may be impacted by loop flows and assumes phase shifting capability of Ontario-Michigan interface is not available.
MRO / ONT			
NW / MAN Lines K21W, K22W	263	263	Summer rating
NW / MIN Line F3M	90	90	
Total	353	353	Feasible Simultaneous Transfer to MAPP.
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 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 1-3 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 demand 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

The 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 (-13.9 °C) and for the summer peak is 90.2 °F (32.3 °C).

New York

The forecast is developed by the NYISO using a Temperature-Humidity Index (THI) value of 84.2 °F (29 °C), which is representative of weather conditions during peak demand conditions. At forecast demand levels, a one-degree increase in the THI will result in approximately 610 MW of additional load. Under extreme conditions the peak demand could reach 34,959 MW for the summer of 2012.

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 on demographic and economic-driver forecasts, 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 load profiles to the annual end-use 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.

In relation to peak demand uncertainty and variability due to weather and/or other conditions, Hydro-Québec has developed hourly chronological load profiles based on a 36-year analysis of historical weather conditions (1971-2006). This methodology is useful to quantify weather uncertainty and its impacts on peak demand. Since Québec has a winter peaking load profile, the load uncertainty is lower during the summer than during the winter. As an example, at the summer peak, weather conditions uncertainty is about 450 MW, equivalent to one standard deviation. During winter, this uncertainty is 1,500 MW. Extreme weather deviations are quantified at about 1,100 MW for the summer peak and at about 4,700 MW for the winter peak.

TransÉnergie – the Québec system operator – then determines the Québec Reliability Coordinator area forecasts using Hydro-Québec Distribution's forecasts (HQ demand) and adding demands of independent systems and agreements with different private systems within the Reliability Coordinator 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 Reliability Coordinator area. 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 Reliability Coordinator 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 reviewed and revised by the NPCC Task Forces.

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 by the NPCC Task Force on Coordination of Operation.

NPCC Regional Reliability Reference Directory #6 – Reserve Sharing Groups

Description: This directory provides the framework for Regional Reserve Sharing Groups within NPCC. It establishes the requirements for these.

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.

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.

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-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

This document outlines 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-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.

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

New Brunswick Power Corporation

<http://www.nbpower.com>

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>

ReliabilityFirst Corporation

<http://www.rfirst.org>

TransEnergie

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

Drought Predictors

Canada

<http://gfx.weatheroffice.ec.gc.ca/saisons/>

United States

<http://www.drought.unl.edu/dm/index.html>

Appendix VII - References

NPCC Reliability Assessment for Summer 2011 - April 2011

NPCC Reliability Assessment for Winter 2011/2012 – November 2011

**Appendix VIII – CP-8 2012 Summer Multi-Area Probabilistic Reliability
Assessment – Supporting Documentation**



**Northeast Power Coordinating Council, Inc.
Multi-Area Probabilistic Reliability
Assessment
For
Summer 2012**

**Draft Report
April 25, 2012**

TFCP Approved Report for RCC Review and Approval

Conducted by the
CP-8 Working Group



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The CP-8 Working Group acknowledges the efforts of Messrs. Glenn Haringa, GE International, Inc, Patricio Rocha, the PJM Interconnection, and thanks them for their assistance in this analysis.



Appendix VIII - CP-8 2012 SUMMER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT – SUPPORTING DOCUMENTATION

FOREWORD

Use of operating procedures designed to mitigate resource shortages (reducing 30-minute reserve, voltage reduction, and reducing 10-minute reserve) is not anticipated during the 2012 summer period under expected conditions. Slower economic growth than anticipated, coupled with the continuing impacts of conservation initiatives has resulted in a lower overall NPCC demand forecast compared to last year. Furthermore, new resources and transmission capacity resulting from transmission projects planned to be available by this summer are additional factors that act to minimize the expected need for the use of these operating procedures in 2012.

Operating procedures are available to maintain reliability for the unlikely simultaneous combination of severe system conditions (such as reductions in anticipated resources, delay of expected transmission projects and/or additional constraints) materializing coincident with higher than expected loads (such as caused by a wide spread, prolonged heat wave with high humidity and near record temperatures).



Appendix VIII - CP-8 2012 SUMMER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT – SUPPORTING DOCUMENTATION

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Appendix VIII - CP-8 2012 SUMMER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT – SUPPORTING DOCUMENTATION

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Appendix VIII - CP-8 2012 SUMMER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT – SUPPORTING DOCUMENTATION

EXECUTIVE SUMMARY

Introduction

This study assessed NPCC Area reliability by estimating the projected use of Area Operating Procedures designed to mitigate resource shortages for the summer of 2012 (May through September). The CP-8 Working Group closely coordinated its efforts with those of the CO-12 Working Group's study, "*NPCC Reliability Assessment for Summer 2012*", April 2012.¹

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

Base Case Results

For the May - September 2012 period, assuming the Base Case conditions, Figures EX-1a and EX-1 b shows there would be no significant likelihood of implementing operating procedures in response to a capacity deficiency for both the expected and extreme load forecasts. The expected load forecast is based upon the probability-weighted average of the seven load levels simulated; the extreme load represents the second highest of the seven load levels, having approximately a 6% chance of occurring.

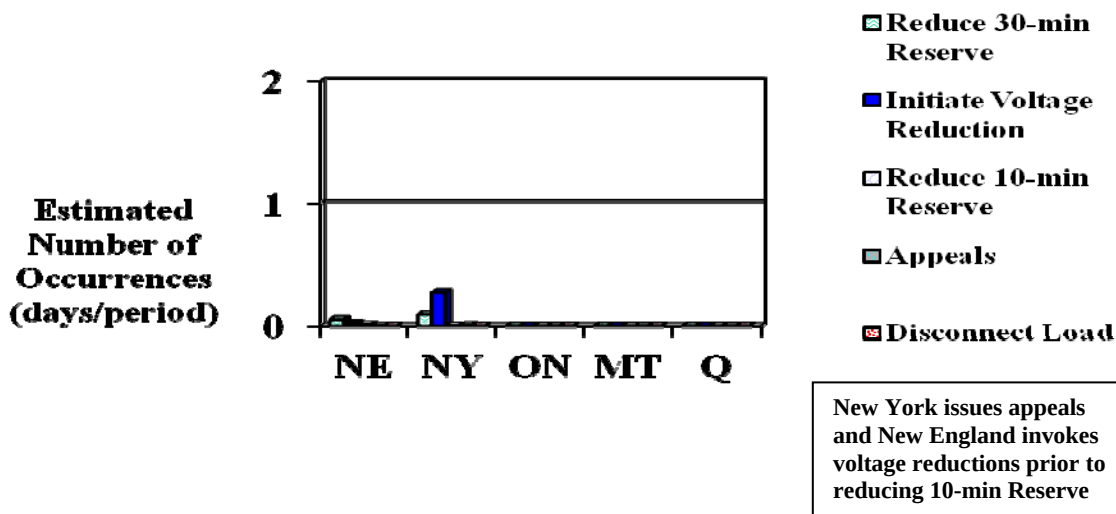


Figure EX-1a
Expected Use of Indicated Operating Procedures for Summer 2012
Considering Base Case Assumptions (May – September)
(Expected Load Forecast)

¹ See: <http://www.npcc.org/seasonal.asp?Folder=CurrentYear>

Appendix VIII - CP-8 2012 SUMMER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT – SUPPORTING DOCUMENTATION

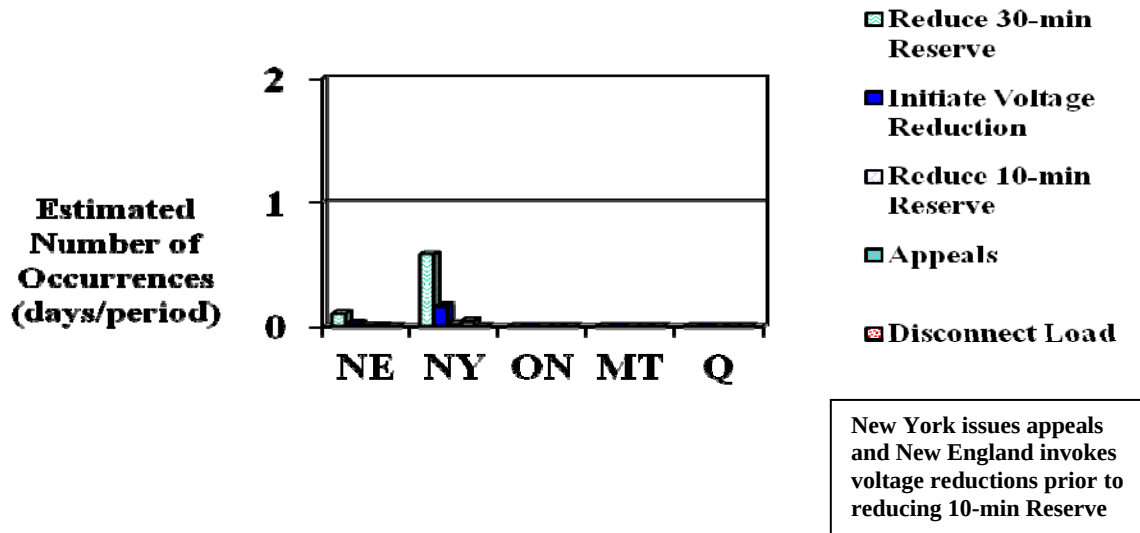


Figure EX-1b
Expected Use of Indicated Operating Procedures for Summer 2012
Considering Base Case Assumptions (May – September)
(Extreme Load Forecast)

Severe Case Results

For the May - September 2012 period, Figure EX-1c shows the expected use of the indicated operating procedures assuming the Severe Case conditions and the expected load forecast.

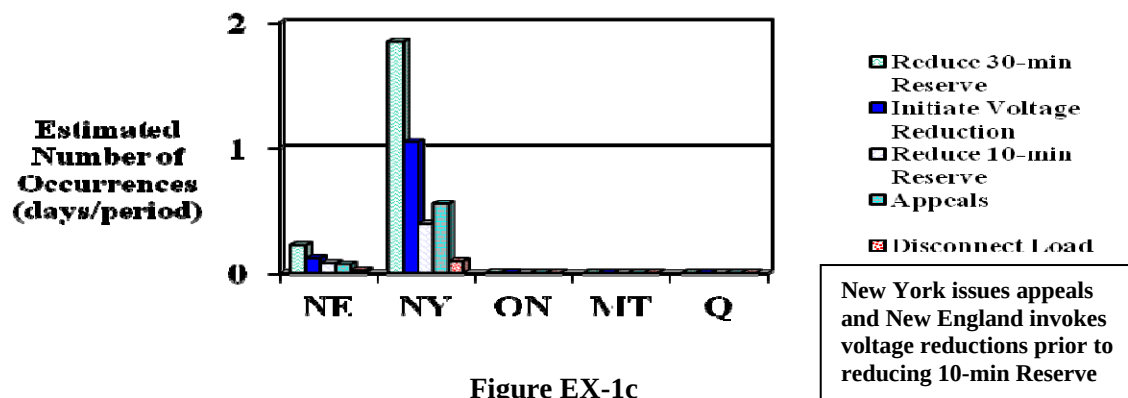


Figure EX-1c
Expected Use of Indicated Operating Procedures for Summer 2012
Considering Severe Case Assumptions (May – September)
(Expected Load Forecast)



Appendix VIII - CP-8 2012 SUMMER MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT – SUPPORTING DOCUMENTATION

For the May - September 2012 period, Figure EX-1d shows the expected use of the indicated operating procedures assuming the Severe Case conditions and the extreme load forecast.

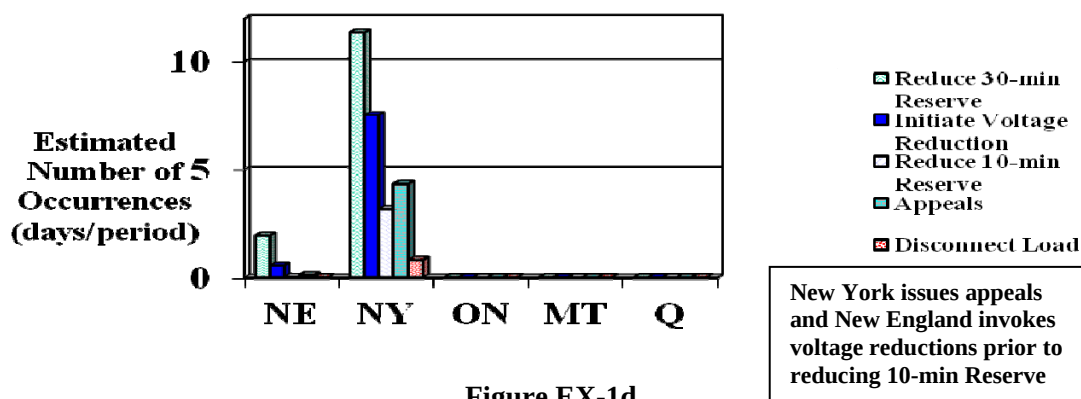


Figure EX-1d
Expected Use of Indicated Operating Procedures for Summer 2012
Considering Severe Case Assumptions (May – September)
(Extreme Load Forecast)

Conclusions

Use of operating procedures designed to mitigate resource shortages (reducing 30-minute reserve, voltage reduction, and reducing 10-minute reserve) is not expected during the 2012 summer period for the Base Case conditions assumed for the expected and extreme load forecast assumptions. Slower economic growth than anticipated, coupled with the continuing impacts of conservation initiatives has resulted in a lower overall NPCC demand forecast compared to last year. Furthermore, new resources and transmission capacity resulting from transmission projects planned to be available this summer are additional factors that act to minimize the expected need for the use of these operating procedures in 2012.

Figures EX-1c (expected load level) and EX-1d (extreme load level), show the possible range of operating procedure use if reductions in anticipated resources, delays of expected transmission projects and/or additional constraints materialize coincident with higher than expected loads (such as caused by a wide spread, prolonged heat wave with high humidity and near record temperatures).

Operating procedures are available to maintain system reliability for this unlikely simultaneous combination of extreme weather and severe system conditions.



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INTRODUCTION

This study assessed the short-term reliability of Northeast Power Coordinating Council, Inc. (NPCC) for the year 2012 by estimating the annual Loss of Load Expectation and use of Area operating procedures to mitigate resource shortages for the summer (June through August) and shoulder (May and September) months. The Working Group closely coordinated its efforts with the CO-12 Working Group's study, "NPCC Reliability Assessment for Summer 2012", April 2012.

The development of this Working Group's assessment was in response to recommendation (5) from the "June 1999 Heat Wave – NPCC Final Report", August 1999 that states:

“The NPCC Task Force on Coordination of Planning (TFCP) should explore the use of a multi-area reliability study tool as a part of an annual resource adequacy review to gain insight into the effects of maintenance schedules and transmission constraints on regional reliability.”

The database developed for the NPCC CP-8 Working Group's "2011 Long Range Adequacy Overview", March 1, 2012,² 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 year 2012 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 3.14 was used in this assessment.

² See:

https://www.npcc.org/Library/Resource%20Adequacy/revDraftLongRangeOverview_March%201,%202012_%20%20RCC%20Approved.pdf



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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 Area's summer peak load assumptions for the year 2012. The values shown for Québec and the Maritimes Area show both their actual summer peak and the peak during the period of NPCC's peak.

Table 1
Assumed NPCC 2012 Summer Peak Loads – MW

Area	2002 Load Shape		
	Expected Peak	Extreme Peak ³	Month
Québec (Q)	22,956 20,989	24,907 22,773	May August
Maritimes Area ⁴ (MT)	3,724 3,352	4,096 3,687	May July
New England (NE)	27,440	30,711	August
New York (NY)	33,295	35,932	August
Ontario (ON)	23,409	25,989	July

An explanation of each Area's expected load forecast and methodology can be found in the companion NPCC CO-12 Working Group Report, "NPCC Reliability Assessment for Summer 2012", April 2012.

NPCC Areas have different definitions for their extreme peak load forecasts. A brief summary of the basis of each NPCC Area's extreme peak load forecasts follows.

Québec

Expected peak load is based on a reference scenario and average weather conditions. Québec doesn't forecast "extreme load" per se. For the purpose of this exercise, the "extreme peak" is based on load forecast uncertainty representing approximately two standard deviations. The impact of weather conditions as well as load forecast uncertainty (economic, demographic, prices) are taken into account in simulations.

³ Extreme peak value based on load forecast uncertainty for referenced peak month.

⁴ The Maritimes Area represents New Brunswick, Nova Scotia, Prince Edward Island, and the area administrated by the Northern Maine Independent System Administrator (NMISA).



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Maritimes Area

The Maritimes Area doesn't forecast "extreme load"; however, load forecast uncertainty is modeled in its reliability analysis. The load forecast uncertainty factors are developed by comparing the historical forecast values of load to the actual loads experienced.

New England

The Independent System Operator of New England (ISO-NE) bases on a 3-day weighted temperature-humidity index (WIHI) for weather conditions in its peak load forecasts. The peak loads that have a 50% chance of being exceeded and are expected to occur at weighted New England-wide temperature of 90.2F are considered as the 50/50 "reference" case. Peak loads with a 10% chance of being exceeded and expected to occur at a weighted New England-wide temperature of 94.2F, are considered the 90/10 "extreme" case.

New York

The New York Independent System Operator (NYISO) bases its extreme load forecast on "one in 15 year" weather extreme for high temperature. The NYISO characterizes extreme weather conditions in terms of the NYISO summer index, which incorporates dry bulb and dew point values (temperature and humidity), as well as a build-up effect (through lagged elements in the equation).

Ontario

Ontario's Independent Electricity System Operator (IESO) uses a multivariate econometric model to forecast energy and peak demand on the IESO controlled grid. Demand is defined as loads plus losses and peak demand refers to the highest hourly value.

The IESO does not directly provide a forecast of "extreme load" for this assessment. The IESO determines a value for load forecast uncertainty representing one standard deviation in demand, derived from the impact of temperature, humidity, cloud cover and wind speed on peak demand. The IESO expected demand and IESO load forecast uncertainty values were provided as input to this assessment.

Load Shape

Based on comparison of the results from the previous analyses, and recent weather experience, the Working Group concluded that the 2002 load shape was representative of a reasonable expected coincidence of Area load for summer 2012. The growth rate in each month's peak was used to escalate Area loads to match the Area's year 2012 demand and energy forecasts. The impacts of Demand-Side Management programs were included in each Area's load forecast, except for New England, where demand response programs are treated as supply resources.



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Figure 1(a) shows the diversity in the NPCC Area load shapes used in this analysis for the composite load shape, which assumes the 2002 load shape for the summer period.

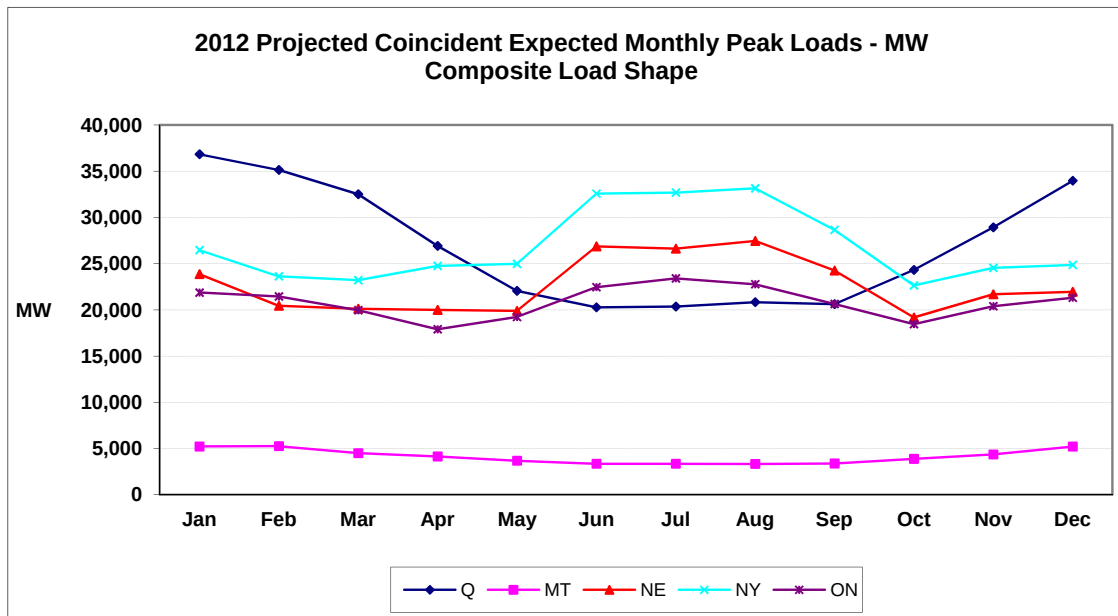


Figure 1 (a) - 2012 Projected Monthly Expected Peak Loads for NPCC Areas ⁵

Figure 1(b) shows the forecast daily summer peaks (June through August) modeled for the summer-peaking NPCC Areas (New England, New York, and Ontario) assuming the 2002 load shape. New England and New York closely track each other, while Ontario shows a similar pattern but with a bit more variation.

⁵ 2003/04 load shape assumed for the November – March period.

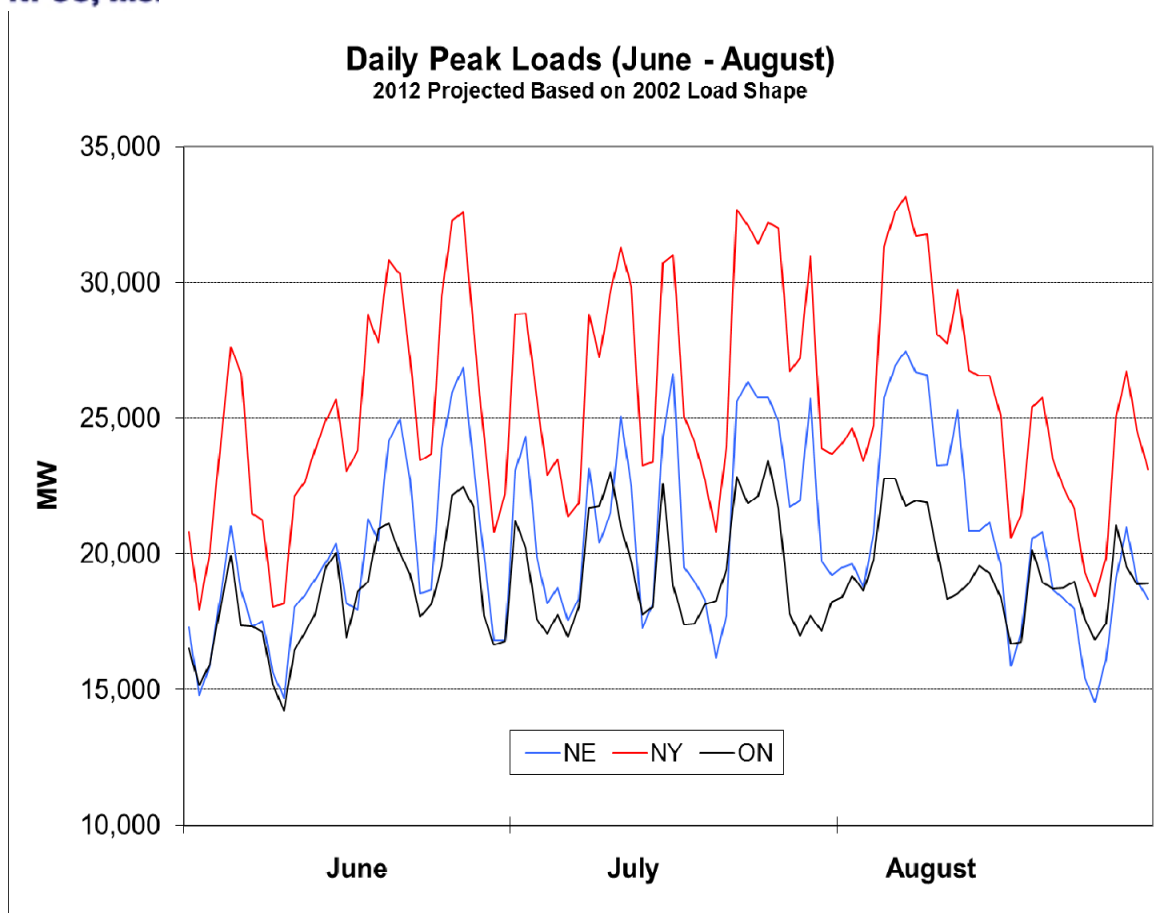


Figure 1(b) – Forecast 2012 Daily Peak Loads Modeled for New England, New York and Ontario (Based on 2002 Load Shape Assumption)

Load Forecast Uncertainty

The effects on reliability of uncertainties in the load forecast, due to weather and 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 the associated probabilities of occurrence.

While the per unit variations in Area and sub Area load can vary on a monthly basis, Table 2 shows the values assumed for August, corresponding to the assumed occurrence of the NPCC system peak load (assuming the 2002 load shape). 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



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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 shaded in Table 2.

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

Area	Per-Unit Variation in Load						
Q	1.0863	1.0850	1.0383	0.9990	0.9617	0.9236	0.9137
MT	1.1000	1.1000	1.0500	1.0000	0.9500	0.9000	0.9000
NE	1.2397	1.1192	1.0039	0.9388	0.8970	0.8864	0.8513
NY	1.0973	1.0792	1.0398	0.9930	0.9418	0.8891	0.8526
ON	1.1653	1.1102	1.0551	1.0000	0.9449	0.8898	0.8347
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Generation

Tables 3(a) and 3(b) summarize the summer 2012 capacity assumptions for the NPCC Areas used in the analysis for the Base Case and the Severe Case Scenario, respectively. Also shown in Table 3(a) is each Area's annual weighted average unit availability percentage, based on each Area's capacity according to the following relationship:

$$\text{Annual Weighted Average Availability (\%)} = (1 - \text{P.O.R.}) \times (1 - \text{F.O.R.})$$

Where: P.O.R. = Total Hours on Planned Outage/Total Number of Hours

F.O.R. = Total Hours on Forced Outage/Total Number of Hours not on Planned Outage



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Table 3(a)
NPCC Capacity and Load Assumptions for Indicated Summer 2012 peak period - MW
Base Case - Expected Load

	Q ⁶ (August)	MT (July)	NE (August)	NY (August)	ON ⁷ (July)
Assumed Capacity	30,673	6,590	31,969	36,911	30,630
Net Purchase (+)/Sale (-)	-1,047	0	676	1,588	0
Peak Load ⁸	20,989	3,352	27,440	33,295	23,409
DR / SCR	0	0	2,106	1,862	1,326
Reserve (%)	42	97	27	21	37
Annual Weighted Average Unit Availability (%)	98.4	89.7	88.6	84.2	84.6
Scheduled Maintenance ⁹	0	1,192 ¹⁰	165	64	174

Table 3(b)
NPCC Capacity and Load Assumptions for Indicated Summer 2012 peak period - MW
Severe Assumptions Scenario - Extreme Load

	Q ⁶ (August)	MT (July)	NE (August)	NY (August)	ON ⁷ (July)
Assumed Capacity	29,641	6,409	31,365	36,411	29,325
Net Purchase (+)/Sale (-)	-1,047	0	676	1,588	0
Peak Load ⁷	22,773	3,687	30,711	35,932	25,989
DR / SCR	0	0	1,053	1,397	1,163
Reserve (%)	26	74	8	10	17
Scheduled Maintenance ⁹	0	1,192 ¹⁰	279	1,091	929

Note: Reserve Margin calculation includes Demand Response (DR) for New England and Ontario, and Special Case Resources (SCR) for New York.

⁶ Capacity shown for Québec adjusted for scheduled maintenance. Annual Weighted Average Unit Availability for Québec does not include scheduled maintenance.

⁷ Capacity shown for Ontario has been seasonally adjusted.

⁸ Based on the 2002 Load Shape assumption.

⁹ Maintenance shown is for the week of the monthly peak load.

¹⁰ Includes scheduled maintenance, deratings, and units on lay-up.



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Unit Availability

Details regarding each NPCC Area's assumptions for generator unit availability are described in the respective Area's most recent "NPCC Comprehensive Review of Resource Adequacy",¹¹ updated for the 2012 summer period as described below.

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 March 2012 – August 2013" (published February 24, 2012).¹²

Ontario market participants provided the majority of generation data. F.O.R. and 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 Corporation (NERC) Generator Availability Data System¹³ (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 Corporation (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 2012/2013 Capability Year.¹⁴

New York

Detailed availability assumptions used for the New York units can be found in the New York ISO Technical Study Report¹⁵ "Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2012 – 2013 Capability Year" and the "New York Control Area Installed Capacity Requirement for the Period May 2012-April 2013" New York State Reliability Council, December 2, 2011 report.¹⁶

¹¹ See: <http://www.npcc.org/adequacy.cfm>

¹² See: http://ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2012feb.pdf

¹³ See: <http://www.nerc.com/page.php?cid=4|43>

¹⁴ See: http://www.iso-ne.com/regulatory/ferc/filings/2011/nov/er12-496-000_11-30-11_icr_2012-2013.pdf

¹⁵ See: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp

¹⁶ See: <http://www.nysrc.org/pdf/Reports/2012%20IRM%20Final%20Report.pdf>

Transfer Limits

Figure 2 depicts the system that was represented in this Assessment, showing Area and assumed Base Case transfer limits for the year 2012. New York Area internal transmission representation was consistent with the assumptions used in the New York ISO Technical Study Report¹⁵ - "*Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2012 – 2013 Capability Year*" and the "*New York Control Area Installed Capacity Requirement for the Period May 2012 – April 2013*" New York State Reliability Council, December 2, 2011 report.¹⁶

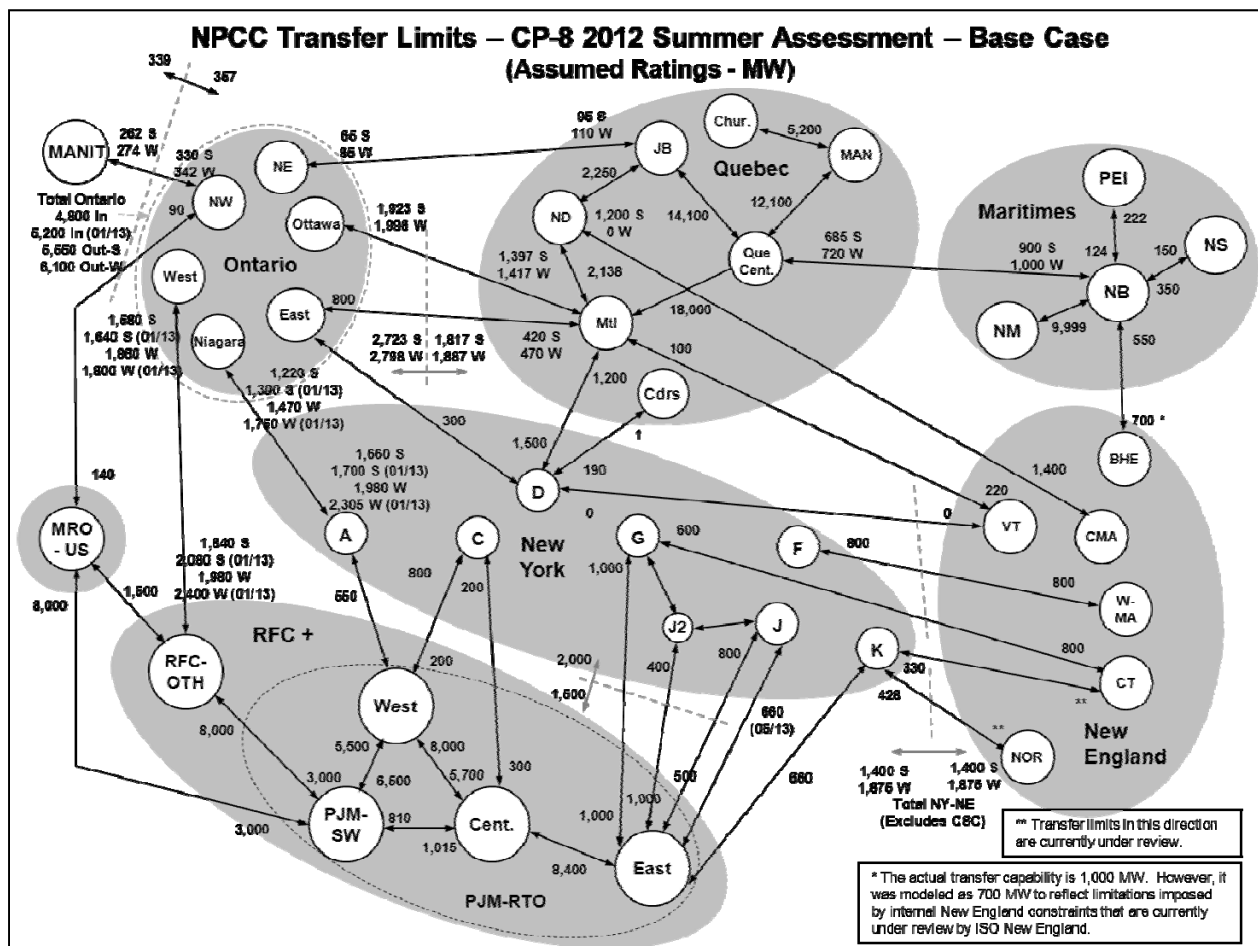


Figure 2 - Assumed Transfer Limits

Note: With the Variable Frequency Transformer operational at Langlois (Cdrs), Hydro-Quebec can import up to 100 MW from New York



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Transfer limits between and within some Areas are indicated in Figure 2 with seasonal ratings (S- summer, W- winter) where appropriate. Details regarding the sub-Area representation for Ontario ¹², New York ¹⁶, and New England ¹⁷ are provided in the respective references. The acronyms and notes used in Figure 2 are defined as follows:

Chur	- Churchill Falls	NOR	- Norwalk – Stamford	NM	- Northern Maine
MANIT	- Manitoba	BHE	- Bangor Hydro Electric	NB	- New Brunswick
ND	- Nicolet-Des Cantons	Mtl	- Montréal	PEI	- Prince Edward Island
BJ	- Bay James	C MA	- Central MA	CT	- Connecticut
MN	- Minnesota	W MA	- Western MA	NS	- Nova Scotia
MAN	- Manicouagan	NBM	- Millbank	NW	- Northwest (Ontario)
NE	- Northeast (Ontario)	VT	- Vermont	RFC	- ReliabilityFirst Corp.
MRO	- Midwest Reliability Organization	Que	- Québec Centre	MT	- Maritimes Area
		Cdrs	- Cedars/Langlois		

The New England internal transmission representation is consistent with assumptions currently being developed for the 2012 New England Regional System Plan. ¹⁷

Phase angle regulators (PARs) are installed on the Ontario – Michigan interconnection at Lambton Transformer Station (L4D and L51D) and Keith (J5D) on the Ontario side and at Bunce Creek Transformer Station (B3N) in Michigan, representing the four interconnections with Michigan. Final regulatory approvals have been received, permitting operation of these facilities. Three PARS were placed in service prior to summer 2012 and are being used to manage circulation power flows around Lake Erie, as well as contingencies.

Operating Procedures to Mitigate Resource Shortages

Each NPCC 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 disconnected. Load control measures could include disconnecting or reducing interruptible loads, making public appeals to reduce demand, and/or implementing voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reducing operating reserves.

The need for an Area to begin these operating procedures is modeled in MARS by evaluating the daily probabilistic expectation 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.

¹⁷ New England Regional System Plan(s) can be found at: <http://www.iso-ne.com/trans/rsp/index.html>.



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Table 4
NPCC Operating Procedures to Mitigate Resource Shortages
2012 Summer Load Relief Assumptions – MW or % of Load (August)

Actions	Q	MT	NE ¹⁸	NY	ON
1. Curtail Load / Utility Surplus	0	0	0	0	148
Appeals	0	0	0	0	1.00%
RT-DR */ SCR / EDRP	0	0	692	143	0
SCR Load / Man. Volt. Red.	0	0	0	5.58%	0
2. No 30-min Reserves	500	162	600	600	473
3. Volt. Red.	0	0	397	1.33%	0
Interruptible Load ¹⁹	0	210	0	0	0
4. No 10-min Reserves	750	467	0	0	1,080
RT-EG ²⁰	0	0	435	0	0
Appeals / Curtailments	0	0	0	231	0
5. 5% Voltage Reduction	0	0	0	0	2.60%
No 10-min Reserves	0	0	1,200	1,200	0

*Real-Time Demand Resource

Assistance Priority

All Areas received assistance on a shared basis in proportion to their deficiency. In this analysis, each step was initiated simultaneously in all Areas and sub-Areas.

¹⁸ Values for New England's Real-Time Demand Resources and Real-Time Emergency Generation have been derated to 554MW and 319MW, respectively to account for historical availability performance.

¹⁹ Interruptible Loads for Maritimes Area (implemented only for the Area), Voltage Reduction for all others (3% Voltage Reduction assumed for Ontario).

²⁰ Real Time Emergency Generation



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Modeling of Neighboring Regions

For the scenarios studied, a detailed representation of the PJM-RTO and neighboring regions of RFC (ReliabilityFirst Corp.) and the MRO-US (Midwest Reliability Organization – US portion) was assumed. The assumptions are summarized in Table 5 and Figure 3.

Table 5
PJM-RTO, RFC-OTH, and MRO-US 2012 Assumptions²¹

	PJM-RTO	RFC-OTH	MRO-US
Peak Load (MW)	164,322	81,593	36,302
Peak Month	July	July	July
Assumed Capacity (MW)	187,642	95,826	41,239
Reserve (%)	13	17	14
Weighted Unit Availability (%)	87.2	87.2	87.3
Operating Reserves	3,400	2,206	1,700
Interruptible Load	7,265	4,194	2,443
No 30-min Reserves	2,765	1,470	1,200
Voltage Reductions	2,201	1,100	1,100
No 10-min Reserves	635	736	500
Appeals	400	200	200
Load Forecast Uncertainty (%)	93.76 +/- 5.37, 10.73, 16.10	93.24 +/- 5.81, 11.62, 17.44	94.51 +/- 4.72, 9.44, 14.15

The diversity between the NPCC monthly peak loads and those of PJM-RTO, RFC-Other, and MRO-US are shown in Figure 3.

²¹ Load and capacity assumptions for RFC-Other based on NERC's Electricity and Supply Database (ES&D) available at: <http://www.nerc.com/~esd/>



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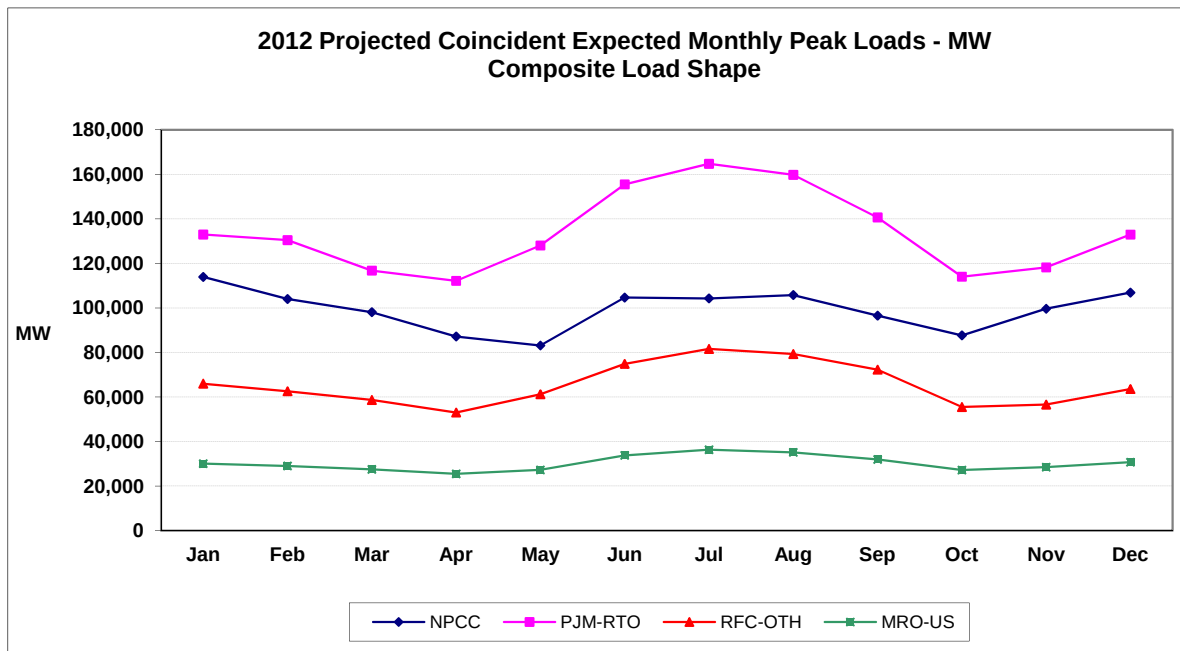


Figure 3 - 2012 Projected Monthly Expected Peak Loads for NPCC, PJM-RTO, RFC-OTH, and MRO-US ⁵

ReliabilityFirst 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.



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PJM-RTO

Load Model

The load model used for the PJM-RTO corresponds to the PJM Planning division's technical methods to produce a load model of the 2012 forecast year.²² The hourly load shape is based on observed 2002 calendar year values, which reflects representative weather and economic conditions for a peak planning study. The hourly loads were then adjusted per the PJM Load Forecast Report, January 2011,²³ for the forecast monthly loads. This study modeled load forecast uncertainty consistent with that used in recent probabilistic PJM models, per the above references, which reflects uncertainty for loads at a predetermined probability of occurrence. This load uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal PJM zones or regions, the period years the model is based on, sampling size, and how many years ahead in the future the load forecast.

Expected Resources

All generators that have been demonstrated to be deliverable were modeled as PJM capacity resources in the PJM-RTO study area. Existing generation resources, planned additions, modifications, and retirements are per the EIA-411 data submission and the PJM planning process. Load Management (LM) is reflected in this model's Emergency Operating Procedure level 1, corresponding to the publicly available data on the PJM web site.²⁴ This modeling of Load Management corresponds to the PJM Operations Staff ability to call up to 10 LM events, in a peak period.

Expected Transmission Projects

The transfer values shown in the study are reflective of peak emergency conditions. PJM is a summer peaking area. The studies performed to determine these transfer values are in line with the Regional Transmission Planning Process employed at PJM, of which the Transmission Expansion Advisory Committee (TEAC) reviews these activities. All activities of the TEAC can be found at the [pjm.com](http://www.pjm.com) web site. All transmission projects are treated in aggregate, with the appropriate timing and transfer values changing in the model, consistent with PJM's regional Transmission Expansion Plan.²⁵

²² Please refer to PJM Manuals 19 and 20 at <http://www.pjm.com/~media/documents/manuals/m19-redline.ashx> and, <http://www.pjm.com/~media/documents/manuals/m20-redline.ashx> for technical specifics.

²³ See: <http://www.pjm.com/~media/documents/reports/2011-load-forecast-report.ashx>

²⁴ See: <http://www.pjm.com/planning/resource-adequacy-planning/~media/documents/reports/2009-pjm-reserve-requirement-study.ashx>

²⁵ See: <http://www.pjm.com/planning.asp>



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ANALYSIS

Summer 2011 Review

The blistering heat experienced by the contiguous United States during August, as well as the June through August months, marked the second-warmest summer (June-August) on record, according to the latest *State of the Climate* report issued by NOAA.²⁶ This analysis, based on records dating back to 1895, is prepared by scientists at NOAA's National Climatic Data Center in Asheville, N.C.

During the six-month period (March-August), much-above-average temperatures dominated the southern and eastern United States. New Mexico, Oklahoma, Texas, Louisiana, South Carolina, and Florida, all experienced their warmest March-August on record. Cooler-than-average temperatures dominated the West and Northwest.

For precipitation year-to-date, New Mexico, Texas, and Louisiana have all had their driest January-August periods on record, while Ohio, Pennsylvania, New York, New Jersey, and Connecticut were record wet during the same period.

Based on NOAA's Residential Energy Demand Temperature Index, the contiguous U.S. temperature-related energy demand was 22.3 percent above average during summer. This is the largest such value during the index's period of record, which dates to 1895.

The continuing effects of slower than expected economic recovery and the impact of conservation programs resulted near forecast electrical demand for the summer of 2011, in spite of the warm weather. The following NPCC Areas reported the use of the indicated operating procedures as shown during the summer of 2011 assessment period in response to the following system conditions:

July 2011 heat wave

New York

Thursday - July 21, 2011

- ✓ Actual peak New York Control Area system load for HB16 was 33, 454 MW
Systems loads > 33, 000 MW from HB15 through HB17
- ✓ National Grid, NYSEG, and RG&E set new record all time peaks
- ✓ Only one bulk power system transmission facility was unavailable - Y49
Sprainbrook-East Garden City 345kV forced out
- ✓ Only one generating facility was unavailable for operation at peak
- ✓ No bulk power system voltage problems that impacted transfer capability
- ✓ Average wind generation was 876 MW from HB10 through HB19
- ✓ EDRP and SCR resources in all Zones were notified for possible next day
activation on 7/20

²⁶ See: http://www.noaanews.noaa.gov/stories2011/20110908_auguststats.html



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- ✓ EDRP and SCR resources were activated in Zones G, H, I, J, and K on 7/21 from HB13 through HB17. EDRP/SCR resources were activated for Zones G-K transmission security operations (requirement to restore system power flows to within normal operating limits)
- ✓ EDRP and SCR estimated value of demand response was 574 MW. Initial review of performance was as requested for five hour period

Friday -July 22, 2011

- ✓ Actual peak New York Control Area system load for HB15 was 33, 865 MW. Systems loads > 33,000 MW from HB11 through HB17
- ✓ Consolidated Edison and Long Island Power Authority set record all time peaks
- ✓ Only one bulk power system transmission facility was unavailable -Y49 Sprainbrook-East Garden City 345kV forced out
- ✓ Only two generating facilities were unavailable for operation at peak
- ✓ No bulk power system voltage problems that impacted transfer capability
- ✓ Average wind generation was 270 MW from HB10 through HB19
- ✓ EDRP and SCR resources in all Zones were notified for possible next day activation on 7/21
- ✓ EDRP and SCR resources were activated in Zone J from HB12 through HB17
- ✓ EDRP and SCR resources were activated in Zone A, B, C, E, F, G, H, I, and K on 7/22 from HB13 through HB17 – EDRP and SCR resources were activated for Zones G-K for transmission security operations
- ✓ EDRP and SCR resources were activated for Zones A-C and E-F to meet statewide capacity requirements in response for import transaction curtailments and nearly 1,600 MW load forecast error (about 90% of the error due to weather forecast error)
- ✓ EDRP and SCR estimated value of demand response was 1, 396 MW. Initial review of performance was as requested for five hour period (six hour period for Zone J)

New England

July 2011 - activation of OP#4 Actions:

- ✓ On Friday, July 22, 2011, ISO New England implemented Operating Procedure #4, 'Action During a Capacity Deficiency,'²⁷ to manage a deficiency in Thirty Minute Operating Reserve. Prior to the operating day, ISO entered MLCC #2, Abnormal Conditions Alert²⁸ at 04:00 on Thursday, 7/21/11 due to the extreme hot weather and heavy load forecasts for Thursday and Friday. The operating

²⁷ **OP4 ACTION 1** - ISO-NE will inform all resources that a capacity shortage exists. Each Generator and Demand Resource with a Capacity Supply Obligation will prepare to provide all associated Operable Capability; ISO-NE will notify via the "Notices" section of the ISO New England website that each "Settlement Only" Generator with real-time obligations and capacity supply obligation should be monitoring the status of the reserve pricing and are required to meet their obligation under the "Shortage Event" definitions in Market Rule 1; Begin to allow the depletion of 30-minute reserve. Implement a Power Caution.

²⁸ Master Local Control Center (MLCC) Procedure #2.



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reserve surplus on Friday morning was projected to be 616 MW, based on a forecast load of 27,610 MW from the Morning Report. Peak hour forced outages and reductions totaled 3,403 MW, against 1,960 MW listed in the Morning Report. Actual temperatures in Hartford were 4 degrees higher than forecasted, and in Boston the actual temperatures were 2 degrees higher than forecasted. The expected net deliveries for the peak hour were 1,586 MW and the actual net deliveries were 1,576 MW. Just prior to noon, a large unit tripped which created a deficiency in thirty minute operating reserve and OP#4 Action 1 was declared at 12:00. At 12:15, Action 2 of OP#4 was declared and 300 MW of Real Time Demand Resources were dispatched at 12:17. At 13:17 the remaining 343 MW of Real Time Demand Resources of OP#4 Action 2 were dispatched. At 13:30, Action 3 of OP#4 was declared. At 16:00, Action 5 of OP#4 was declared in order to restore thirty minute operating reserve within four hours in accordance with NPCC requirements. By 17:45, sufficient resources were available which allowed for the cancellation of Actions 2 and 5 of OP#4. As load continued to decrease, Actions 1 and 3 of OP#4 were cancelled at 19:00.

- ✓ The preliminary peak demand for Friday was 27,762 MW, 152 MW above the forecast 27,610 MW value. MLCC #2 was cancelled at 16:00 on 7/23/11. The relief estimated from Action 2 is based upon the Real Time Demand Resource dispatch of 644 MW.

Action(s)	Implemented	Canceled
MLCC#2	04:00 on 7/21/11	16:00 on 7/23/11
OP#4 Action 1	12:00	19:00
OP#4 Action 2	12:15	17:45
OP#4 Action 3	13:30	19:00
OP#4 Action 5	16:00	17:45

August 2011 – Hurricane Irene

Weather Conditions in New England - early forecasts indicated potential Category 3 hurricane in Connecticut; storm hit as a high end tropical storm and the track crossed through Connecticut and Western Massachusetts on Sunday afternoon with Hurricane force gusts in areas of New England causing extensive flooding in the region.

- ✓ Actions taken by ISO New England
 - MLCC #2 –Abnormal Conditions Alert was declared at 12:00 PM, on Friday, August 26th and lasted until 3:30 p.m. on Friday, September 2nd
 - Outages of generation and transmission recalled
 - No outages were allowed to begin
 - Additional generation committed to provide storm support in event of system contingencies
 - Uncertainty about availability of nuclear units in case of high winds



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- Uncertainty about precise track and intensity of the storm
- Thermal and voltage support under multiple contingencies
- Minimum Generation Emergency - Sunday 12:15 to 20:30; Sunday/Monday 23:00 to 09:00 and Tuesday 02:30 to 06:00

Table 6 compares each NPCC Area’s actual 2011 summer peak demands against the forecast assumptions .

Table 6
NPCC 2011 Summer Peak Loads Actual versus Forecast – MW

Area	Actual Peak	Date	2002 Load Shape		
			Expected Peak	Extreme Peak	Month
Québec	21,356	July 21	20,615	21,932	August
Maritimes	3,725	May 16	3,560	3,916	June
New England	27,707 ²⁹	July 22	27,550	30,834	August
New York	33,865	July 22	33,182	35,893	August
Ontario	25,342 ³⁰	July 21	23,561	26,176	July

²⁹ The metered peak demand of 27,707 MW reflects reductions of 710 MW due to real-time demand response resources that were activated that day as part of ISO-NE’s Operation Procedure #4, as well as 1,077 MW of energy efficiency and 34 MW of real-time Price Response; the weather normalized value is 27,240 MW.

³⁰ The weather corrected value is 23, 561 MW.



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2012 Base Case Results

The Working Group modified the Working Group's 2011 NPCC Long Range Adequacy Overview MARS database for the conditions expected for the year 2012.

Tables 7(a) - assuming no import capability from NY to NE over the CSC and from Northport to Norwalk and 7(b) - assuming 330 MW import capability from NY to NE over the CSC and 430 MW from Northport to Norwalk (see Appendix B) shows the estimated need for the indicated operating procedures (in days/period) during May through September 2011 for the Severe Case Scenario for all NPCC Areas. Comparisons of the results indicate there is no material impact in the results of this study from the two assumptions.

For the May - September 2012 period, assuming the Base Case conditions and the expected load forecast, it is anticipated there would be no significant likelihood of implementing operating procedures in response to a capacity deficiency.

Only New York shows a slight chance (less than one occurrence) of reducing their 30-minute reserve under the Base Case conditions for the extreme load forecast.

Base Case Assumptions

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 Summer 2012", April 2012. The Base Case assumptions are summarized below:

System

- As-Is System for the year 2012
- Transfers allowed between Areas
- 2002 Load Shape adjusted to Area's year 2012 forecast (expected and extreme assumptions)

Ontario

- Forecast consistent with the IESO's 18-Month Outlook – (published February 24, 2012) ¹²
- 1,510 MW of installed Wind Generation (seasonal wind capacity contribution of about 13% at peak)
- Existing and Planned Demand Responses modeled
- Conservation effects modeled
- Michigan – Ontario Phase Angle Regulators: PAR on J5D is in-service; PARs on circuits L4D, L51D and B3N are bypassed
- Niagara – New York interconnection: Limits reduced for circuit BP-76 outage



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New England

- ~ 32,000 MW of existing and planned generation resources modeled
- ~ 2,106 MW of demand supply resources modeled
- ~ 776 MW of capacity import

New York

- All cables in service
- Assumptions consistent with the NYCA Installed Capacity Requirements for the Period May 2012 Through April 2013
- ~ 2192 MW of registered SCR resources discounted to historic availability (1862 MWs modeled) (July/August). Load SCR resources also modeled in proportion to monthly peak zonal load.
- ~ 148 MW of load reduction from EDRP resources (July/August) discounted to historic availability (95MW modeled)
- Bayonne Energy Center on-line May 1, 2012 (500 MW)

Maritimes

- ~ 790 MW of installed wind generation (~20 % assumed on summer peak)
- Pt. Lepreau scheduled outage through October 1, 2012

Québec

- Existing resources modeled consistent with the 2011 Quebec Comprehensive Review for the Summer 2012 period, including 8,600 MW of maintenance and restrictions
- 1,057 MW of installed wind generation (derated at 100 % percent)
- Over 2,000 MW of firm sales to New York, New England, and Ontario (Cornwall)

PJM-RTO

- As-Is System for the Summer 2012 period – based on the PJM 2011 Reserve Requirement Study³¹
- 2002 Load Shapes adjusted to the 2012 forecast provided by PJM
- Load forecast uncertainty of 94.13 % +/- 5.05%, 10.10%, and 15.15%
- Operating Reserve 3,400 MW (30-min. 2,765 MW; 10-min. 635 MW)
- ~2,500 MW of high ambient temperature generator derates

RFC ‘Other’³²

- As-Is System for the Summer 2012 period – based on NERC ES&D database, updated by the respective ISOs, compiled by PJM staff.
- 2002 Load Shapes adjusted to the most recent monthly forecast provided by PJM
- Load forecast uncertainty of 94.01% +/- 5.15%, 10.30%, and 15.44%
- Operating Reserve 2,206 MW (30-min. 1,470 MW; 10-min. 736 MW)

³¹ 2011 PJM Reserve Requirement Study (RRS), dated October 13, 2011 - available at this link on PJM Web site:

<http://pjm.com/planning/resource-adequacy-planning/~media/planning/res-adeq/2011-rrs-study.ashx>.

³² “RFC Other” refers to previous (before RFC – circa 2006) NERC regional boundaries of ECAR and MAIN, excluding PJM’s territory.



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MRO-US

- As-Is System for the Summer 2012 period - based on NERC ES&D database, updated by the respective ISOs, compiled by PJM staff.
- 2002 Load Shapes adjusted to the most recent monthly forecast provided by PJM
- Load forecast uncertainty of 94.30% +/- 4.90 %, 9.81 %, and 14.71%
- Operating Reserve 1,700 MW (30-min. 1,200 MW; 10-min. 500 MW)

New York Details

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 ¹⁵ - "Locational Installed Capacity Requirements Study covering the New York Control Area for the 2012 – 2013 Capability Year" and New York State will meet the capacity requirements described in the "New York Control Area Installed Capacity Requirements for the Period May 2012 – April 2013" New York State Reliability Council, December 2, 2011 Technical Study Report. ¹⁶

The New York unit ratings were obtained from the "2011 Load & Capacity Data of the NYISO" (Gold Book ³³).

Existing Resources

All in-service New York generation resources were modeled.

Retirements

<u>Project Name</u>	<u>(MW)</u>	<u>Location</u>
Glenwood ST04	116.0	Zone K
Glenwood ST05	113.2	Zone K
Far Rockaway ST04	105.0	Zone K
Barrett GT7	17.0	Zone K
Beebee	15.0	Zone B
Sithe Massena ³⁴	82.2	Zone D
Ravenswood 3-4	31.7	Zone J

Planned Units for 2012

The following units had a signed interconnection agreement by August 1, 2011.

<u>Project Name</u>	<u>(MW)</u>	<u>Location</u>
BP Solar	32	Zone K
EnXco Solar ³⁵	6.5	Zone K
Bayonne Energy Center	500	Zone J

³³ See:

http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2011_Gold_Book_Public_Final.pdf

³⁴ Power City Partners has since rescinded its intention to retire Sithe Massena.

³⁵ Unit does not meet inclusion rules to be reported in the 2012 New York Gold Book.



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Additional Unavailable Units

Unit	Zone	Unavailability Date	Summer Capability (MW)
Astoria 2	Zone J	6/11/2012	182.8
Astoria 4	Zone J	Currently on outage	381.2
Gowanus 1	Zone J	6/11/2012	133.8
Gowanus 4	Zone J	6/11/2012	133.5
Astoria GT 10	Zone J	5/1/2012	17.5
Astoria GT 11	Zone J	7/1/2012	16.4
Binghamton Cogen	Zone C	2/15/2012	41.3
		Total MWs	906.5

Wind resources exhibit daily output variation that correlates to wind speed and density. One approach would be to model wind resources with 90% summer and 70% winter derate factors. The NYISO/NYSERDA Wind Study Phase 2 prepared by GE Energy Consulting³⁶ have shown these availability factors may be appropriate. However, the MARS model only captures monthly rating changes and not the daily changes necessary to accurately model this variation.

The NYISO's approach is to model wind resources as load modifiers with a 90% summer derate factor. Hourly wind readings taken at or near each wind resource are converted to hourly unit MW output. Wind density, turbine height, and other factors are taken into account. These hourly MW output values are then netted against the hourly zonal load. New York uses historic hourly wind readings taken in 2002. This wind study year also corresponds to the base hourly load shape year used in this assessment.

Special Case Resources and Emergency Demand Response Programs

Special Case Resources (SCRs) are loads capable of being interrupted, and distributed generators, rated at 100 kW or higher, that are not directly telemetered. SCRs offer load curtailment as ICAP resources and provide energy/load curtailment when activated in accordance with the NYISO Emergency Operating Manual. SCRs are required to respond to a deployment request for a minimum of four hours, however there is no limit to the number of calls or the time of day in which the Special Case Resources may be deployed.

³⁶ See: http://www.nyiso.com/public/services/planning/special_studies.jsp



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SCRs receive a capacity payment for load curtailment capability sold in the ICAP market and an energy payment for energy performance during a demand response event.

The Emergency Demand Response Program (EDRP) is a voluntary reliability program that allows registered interruptible loads and standby generators when activated in accordance with the NYISO Emergency Operating Manual.. EDRP resources are only paid for their energy performance during a demand response event. There is no limit to the number of calls or the time of day in which EDRP resources may be deployed.

SCRs and EDRPs are modeled as an operating procedure step activated to minimize the probability of customer load disconnection. The GE-MARS models the NYISO operations practice of only activating operating procedures in zones from which are capable of being delivered.

For this study, SCRs (Load) were modeled as a percentage (5.49%) of the load. At the time of the August New York peak, this amount was further discounted by 74% in based on historical availability to 1,862 MW.

EDRPs are modeled as a 148 MW operating procedure step in July and August and they are also limited to a maximum of five EDRP calls per month. This value is discounted based on actual experience from the forecast registered amount to 95 MW.

New England Details

The New England generating unit's ratings were consistent with their summer seasonal capability for the 2012/13 CELT report.

Demand Supply Resources

The passive non-dispatchable demand resources, On-Peak and Seasonal-Peak, are expected to provide ~970 MW of load relief during the peak hours. About 1,127 MW of active demand resources, including Real-Time Demand Resources and Real-Time Emergency Generation Resources, provide additional 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*. These demand resources are discounted in the assessment to account for performance based on the observed availability factors of demand response programs in the past.

Ontario Details

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" (dated February 24, 2012).¹²



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Existing Resources

All in-service Ontario generation resources were modeled.

2012 Resource Additions

Project Name	Zone	Fuel Type	Estimated Effective Date	Planned (MW)
Bruce Unit 2	Bruce	Uranium	2012-Q1	750
Comber Wind Limited Partnership	West	Wind	2012-Q1	166
Pointe Aux Roches Wind	West	Wind	2012-Q1	49
York Energy Centre	Toronto	Gas	2012-Q1	393
Bruce Unit 1	Bruce	Uranium	2012-Q2	750

For the purposes of this assessment, the IESO assumed that wind generation has a dependable contribution of 13% of the installed generation capacity.

All of the dispatchable demand response resources in Ontario total 1,326 MW for the summer period. In addition, the study assumed 188 MW is available from Utility Surplus (a/k/a “Stretch” Capability) called as a part of operating procedures.

2012 Severe Case Results

Tables 8(a) - assuming no import capability from NY to NE over the CSC and from Northport to Norwalk and 8(b) - assuming 330 MW import capability from NY to NE over the CSC and 430 MW from Northport to Norwalk (see Appendix B) shows the estimated need for the indicated operating procedures (in days/period) during May through September 2011 for the Severe Case Scenario for all NPCC Areas. Comparisons of the results indicate there is no material impact in the results of this study from the two assumptions.

Figure 4(a) shows the expected use of the indicated operating procedures occurrences under the Severe Case assumptions for the expected load. The expected load level results were based on the probability-weighted average of the seven load levels simulated.

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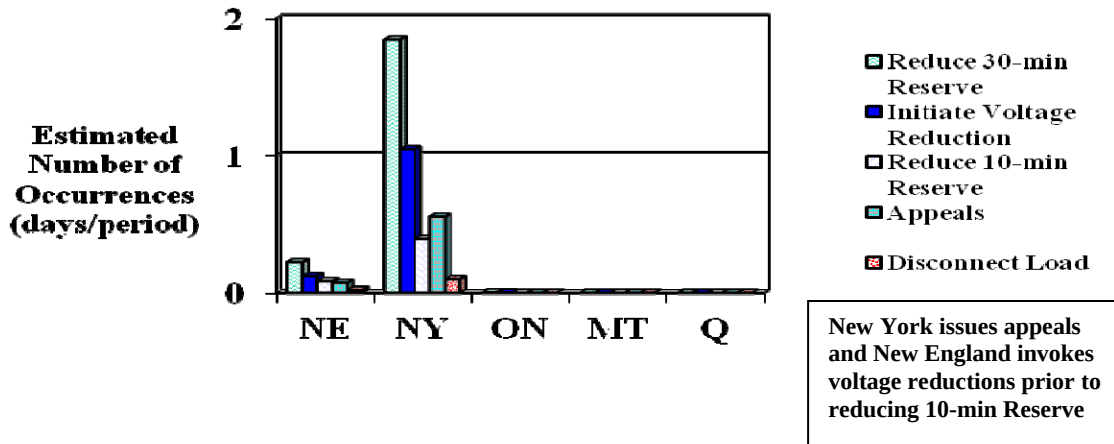


Figure 4(a) - Summer 2012 – Expected Use of the Indicated Operating Procedures Severe Case Assumptions, Expected Load Level (May – September)

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

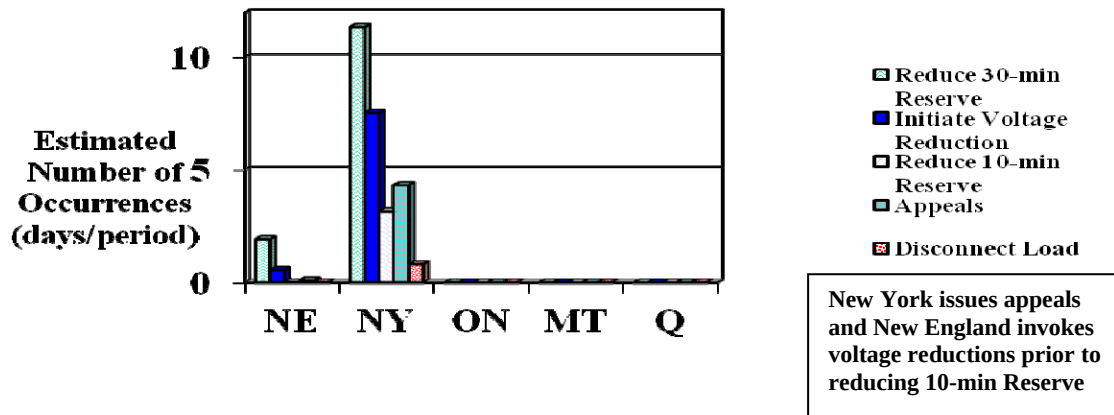


Figure 4(b) - Summer 2012 – Expected Use of the Indicated Operating Procedures Severe Case Assumptions, Extreme Load Level (May – September)

Severe Case Assumptions

The Severe Case Scenario assumptions are summarized below:

System

- As-Is System for the year 2012
- Transfers allowed between Areas
- Transfer capability between NPCC and MRO/RFC- 'Other' reduced by 50%
- 2002 Load Shape adjusted to Area's year 2011 forecast (expected and extreme assumptions)



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Ontario

- ~750 MW of maintenance extended into the summer period
- Bruce 2 in-service date is delayed by 3 months (to June 2012)
- Bruce 1 in-service date is delayed beyond the summer period
- Only existing Demand Response modeled
- Hydro electric capacity and energy 10% lower than the Base Case

New England

- Assume 50% reduction in Demand Resources - Maintenance overrun by 4 weeks
- Assume Vermont Yankee unit unavailable

New York

- Extended maintenance of 1,000 MW in the southeastern New York throughout summer
- Bayonne Energy Center delayed until November 2012
- 25% reduction in effectiveness of SCR and EDRP programs
- 330 MW of assumed cable transmission transfer reduction resulting from component failures within the Neptune and Cross Sound HVDC facilities

Maritimes

- No generation from wind resources assumed

Québec

- Gentilly-2 nuclear station (620 MW) and two units of Manic 5 (206 MW each) unavailable for the summer.

PJM-RTO

- Based on the following PJM 2010 Reserve Requirement Study – Appendix B (Sensitivity Cases) assumptions:³⁷
 - Load forecast uncertainty increased by one percent
 - Forced Outage rates increased for all units by 1.5 percent
 - ~2,500 MW on maintenance extended through the summer period (June-August)
 - ~5,000 MW of additional high ambient temperature generator derates (June-August)
- 90% compliance of DR + EE resources

³⁷ 2010 PJM Reserve Requirement Study (RRS), dated September 20, 2010 - available at this link on PJM Web site: <http://pjm.com/planning/resource-adequacy-planning/~media/documents/reports/2010-pjm-reserve-requirement-study.ashx>



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Conclusions

Use of operating procedures designed to mitigate resource shortages (reducing 30-minute reserve, voltage reduction, and reducing 10-minute reserve) is not expected during the 2012 summer period for the Base Case conditions assumed for the expected and extreme load forecast assumptions. Slower economic growth than anticipated, coupled with the continuing impacts of conservation initiatives has resulted in a lower overall NPCC demand forecast compared to last year. Furthermore, new resources and transmission capacity resulting from transmission projects planned to be available this summer are additional factors that act to minimize the expected need for the use of these operating procedures in 2012.

Figures 4(a) (expected load level) and 4(b) (extreme load level), show the possible range of operating procedure use if reductions in anticipated resources, delays of expected transmission projects and/or additional constraints materialize coincident with higher than expected loads (such as caused by a wide spread, prolonged heat wave with high humidity and near record temperatures).

Operating procedures are available to maintain system reliability for this unlikely simultaneous combination of extreme weather and severe system conditions.



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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 year 2012 under Base Case and Severe Case assumptions, and summarize the range of results for the summer and shoulder season months (the period from May to September).

2. Scope

In meeting this objective, the CP-8 Working Group will review the short-term resource adequacy of NPCC and neighboring Areas for the year 2012, recognizing uncertainty in forecasted demand, scheduled outages of transmission, forced and scheduled outages of generation facilities, and the impact of proposed load response programs. A report summarizing the results of the assessment will be published no later than April 30, 2012. The assessment will:

1. Review last summer's CP-8 Working Group Summer assessments with respect to actual Area experience;
2. Consider the impacts of Sub-Area transmission constraints;
3. Incorporate, to the extent possible, a detailed GE MARS reliability representation for the regions bordering NPCC;
4. Coordinate assessment assumptions with the NPCC Task Force on Coordination of Operations; and,
5. Examine any impact of evolving market rules on overall NPCC interconnection assistance and other assumptions.



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APPENDIX B

Table 7(a) - Base Case
(with no import capability from NY to NE over the CSC and from the Northport to Norwalk)
Expected Need for Indicated Operating Procedures (days/period)
 (Occurrences 0.5 or greater are highlighted)

Base Case																							
	Québec				Maritimes				New England					New York					Ontario				
	30-min	VR	10-min	Appeal	30-min	VR	10-min	Appeal	30-min	VR	10-min	Appeal	Discon	30-min	VR	Appeal	10-min	Discon	30-min	VR	10-min	Appeal	
2002 Load Shape-Expected Load																							
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
June	-	-	-	-	-	-	-	-	0.011	0.005	0.002	0.001	-	0.019	0.006	0.002	0.001	-	-	-	-	-	
July	-	-	-	-	-	-	-	-	0.020	0.006	0.002	0.001	-	0.041	0.010	0.002	0.001	-	-	-	-	-	
Aug	-	-	-	-	-	-	-	-	0.024	0.013	0.007	0.004	-	0.030	0.011	0.004	0.002	-	-	-	-	-	
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
May-Sept	-	-	-	-	-	-	-	-	0.055	0.024	0.011	0.006	-	0.090	0.027	0.008	0.004	-	-	-	-	-	
2002 Load Shape-Extreme			Load								-	-	-	-	-	-	-	-	-	-	-	-	
May	-	-		-	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
June	-	-	-	-	-	-	-	-	0.037	0.008	0.004	0.003	-	0.137	0.043	0.010	0.007	-	-	-	-	-	
July	-	-	-	-	-	-	-	-	0.026	0.007	0.002	0.001	-	0.271	0.064	0.017	0.007	-	-	-	-	-	
Aug	-	-	-	-	-	-	-	-	0.056	0.010	0.001	0.001	-	0.172	0.053	0.013	0.003	-	-	-	-	-	
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
May-Sept	-	-	-	-	0.001	-	-	-	0.119	0.025	0.007	0.005	-	0.580	0.160	0.040	0.017	-	-	-	-	-	

Notes: "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction;
 "10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" - and disconnect customer load

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APPENDIX B

Table 7(b) - Base Case
(with 330 MW import capability from NY to NE over the CSC and 430 MW from Northport to Norwalk)

Expected Need for Indicated Operating Procedures (days/period)

(Occurrences 0.5 or greater are highlighted)

Base Case																						
	Québec				Maritimes				New England					New York					Ontario			
	30-min	VR	10-min	Appeal	30-min	VR	10-min	Appeal	30-min	VR	10-min	Appeal	Discon	30-min	VR	Appeal	10-min	Discon	30-min	VR	10-min	Appeal
2002 Load Shape-Expected Load																						
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	-	-	-	0.010	0.004	0.002	0.001	-	0.019	0.006	0.002	0.001	-	-	-	-	-
July	-	-	-	-	-	-	-	-	0.018	0.005	0.002	0.001	-	0.041	0.010	0.002	0.001	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	0.023	0.011	0.006	0.003	-	0.031	0.012	0.004	0.002	-	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May-Sept	-	-	-	-	-	-	-	-	0.051	0.020	0.010	0.005	-	0.091	0.028	0.008	0.004	-	-	-	-	-
2002 Load Shape-Extreme Load																						
May	-	-	-	-	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	-	-	-	0.033	0.007	0.003	0.001	-	0.137	0.043	0.010	0.007	-	-	-	-	-
July	-	-	-	-	-	-	-	-	0.013	0.002	0.002	0.001	-	0.271	0.064	0.017	0.007	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	0.045	0.005	0.001	0.001	-	0.173	0.053	0.013	0.003	-	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May-Sept	-	-	-	-	0.001	-	-	-	0.091	0.014	0.006	0.003	-	0.581	0.160	0.040	0.017	-	-	-	-	-

Notes: "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction;

"10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" - and disconnect customer load

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APPENDIX B

Table 8(a) - Severe Case
(with no import capability from NY to NE over the CSC and from the Northport to Norwalk)
- Expected Need for Indicated Operating Procedures (days/period)
 (Occurrences 0.5 or greater are highlighted)

Severe Case Results																						
	Québec				Maritimes				New England					New York					Ontario			
	30-min	VR	10-min	Appeal	30-min	VR	10-min	Appeal	30-min	VR	10-min	Appeal	Discon	30-min	VR	Appeal	10-min	Discon	30-min	VR	10-min	Appeal
2002 Load Shape-Expected Load																						
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	-	-	-	0.047	0.021	0.015	0.013	0.003	0.375	0.215	0.116	0.080	0.017	-	-	-	-
July	-	-	-	-	-	-	-	-	0.069	0.041	0.028	0.024	0.003	0.907	0.510	0.268	0.192	0.049	0.003	0.001	-	-
Aug	-	-	-	-	-	-	-	-	0.104	0.055	0.036	0.031	0.013	0.558	0.318	0.165	0.120	0.028	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May-Sept	-	-	-	-	-	-	-	-	0.220	0.117	0.079	0.068	0.019	1.840	1.043	0.549	0.392	0.094	0.003	0.001	-	-
2002 Load Shape-Extreme Load																						
May	--	-	-	-	0.004	0.004	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	-	-	-	0.465	0.122	0.049	0.033	-	1.957	1.318	0.845	0.629	0.151	-	-	-	-
July	-	-	-	-	-	-	-	-	0.345	0.066	0.016	0.010	-	5.911	4.102	2.297	1.661	0.455	0.167	-	-	-
Aug	-	-	-	-	0.001	0.001	-	-	1.133	0.371	0.121	0.064	0.003	3.463	2.099	1.181	0.860	0.197	0.002	-	-	-
Sept	-	-	-	-	0.004	0.004	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May-Sept	-	-	-	-	0.009	0.009	0.003	-	1.943	0.559	0.186	0.107	0.003	11.331	7.519	4.323	3.150	0.803	0.169	-	-	-

Notes: "30-min"- reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction;
 "10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" - and disconnect customer load



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APPENDIX B

Table 8(b) - Severe Case
(with 330 MW import capability from NY to NE over the CSC and 430 MW from Northport to Norwalk)
- Expected Need for Indicated Operating Procedures (days/period)
 (Occurrences 0.5 or greater are highlighted)

Severe Case Results																						
	Québec				Maritimes				New England					New York					Ontario			
	30-min	VR	10-min	Appeal	30-min	VR	10-min	Appeal	30-min	VR	10-min	Appeal	Discon	30-min	VR	Appeal	10-min	Discon	30-min	VR	10-min	Appeal
2002 Load Shape-Expected Load																						
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	-	-	-	0.047	0.021	0.015	0.013	0.003	0.375	0.215	0.116	0.080	0.017	-	-	-	-
July	-	-	-	-	-	-	-	-	0.069	0.041	0.028	0.024	0.003	0.907	0.510	0.268	0.192	0.049	0.003	0.001	-	-
Aug	-	-	-	-	-	-	-	-	0.103	0.055	0.036	0.031	0.012	0.558	0.318	0.166	0.120	0.028	-	-	-	-
Sept	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May-Sept	-	-	-	-	-	-	-	-	0.219	0.117	0.079	0.068	0.018	1.840	1.043	0.550	0.392	0.094	0.003	0.001	-	-
2002 Load Shape-Extreme Load																						
May	--	-	-	-	0.004	0.004	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	-	-	-	0.465	0.118	0.048	0.033	-	1.958	1.318	0.845	0.629	0.151	-	-	-	-
July	-	-	-	-	-	-	-	-	0.345	0.064	0.014	0.008	-	5.913	4.102	2.298	1.661	0.455	0.167	-	-	-
Aug	-	-	-	-	0.001	0.001	-	-	1.127	0.369	0.119	0.063	0.002	3.463	2.099	1.181	0.860	0.197	0.002	-	-	-
Sept	-	-	-	-	0.004	0.004	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May-Sept	-	-	-	-	0.009	0.009	0.003	-	1.936	0.551	0.181	0.104	0.002	11.334	7.519	4.324	3.150	0.803	0.169	-	-	-

Notes: "30-min"- reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction;
 "10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" - and disconnect customer load



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APPENDIX C

Multi-Area Reliability Simulation Program Description

General Electric's Multi-Area Reliability Simulation (MARS) program³⁸ 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.

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.

³⁸ See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm



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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.

Thermal Units

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.



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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:

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

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 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.



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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.

From: [Tina McClellan](#)
To: [Tina McClellan](#)
Subject: NERC ANNOUNCEMENT: NERC Draft 2013 Business Plan and Budget Conference Call and Webinar
Date: Thursday, April 26, 2012 5:36:50 PM

Announcement: **UPDATED** NERC Draft 2013 Business Plan and Budget

On **Thursday**, May 3, 2012 at 10:00 a.m. Eastern, NERC will conduct a webinar and conference call to provide an overview and summary of the first draft of NERC's 2013 Business Plan and Budget. Materials will be posted and announced in advance of the call. It will be recorded and available on NERC's website after completion for anyone not able to listen in at the scheduled time.

To register for the webinar click here: <https://cc.readytalk.com/r/wvbsipzwmelh>

For more information or assistance, please contact [Tina McClellan](#) (via email) or 404-446-2564.

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NORTHEAST POWER COORDINATING COUNCIL, INC.
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March 9, 2012

Members/Alternates: Regional Standards Committee

Dear Members/Alternates:

The Regional Standards Committee will meet on September 5-6, 2012 at the Marriott SpringHill Suites Old Montreal at 445 Rue Saint-Jean-Baptiste in Montreal Canada.

The meeting will begin at 10 a.m. to 5 p.m. on Wednesday, September 5th and 8 a.m. to 3 p.m. on Thursday, September 6th.

The hotel is holding a group of guestrooms for September 4-5, 2012 at \$155.00 per night until August 4, 2012.

For reservations, call (514) 875-4333 or 1-877-875-4333 (toll free) and please mention **NPCC Meeting Hydro-Québec** to receive the group rate. Check-in is at 3:00 pm and checkout is at 12:00 pm.

If I can be of any further assistance, please contact me at (212) 840-1070.

Sincerely,
Francine Cox

Francine Cox
Meeting Coordinator/Administrative
Assistant

FC/fc