BEFORE THE
MINISTRY OF ENERGY OF
THE PROVINCE OF NEW BRUNSWICK

NORTH AMERICAN ELECTRIC	**)**
RELIABILITY COUNCIL and	**)**
NORTH AMERICAN ELECTRIC	**)**
RELIABILITY CORPORATION	**)**

NOTICE OF FILING OF RELIABILITY STANDARDS

The North American Electric Reliability Council, on behalf of its affiliate, the North American Electric Reliability Corporation[1], hereby applies for recognition of the 102 proposed reliability standards set out in Exhibit A. NERC is simultaneously filing these reliability standards for approval with the U.S. Federal Energy Regulatory Commission ("FERC") and for recognition with the Provinces of Alberta, Nova Scotia, Ontario, and the National Energy Board. NERC is also filing a Notice of Filing of Reliability Standards with the Provinces of British Columbia, Manitoba, Québec, and Saskatchewan.[2]

In a companion filing, NERC is filing an Application for Certification as the electric reliability organization (ERO) with the U.S. Federal Energy Regulatory

[1] The North American Electric Reliability Council ("NERC Council") has formed an affiliate, the North American Electric Reliability Corporation ("NERC Corporation"). These organizations may be separately or collectively referred to herein as "NERC".
[2] As explained below, NERC files today Applications for Recognition with those jurisdictions in Canada that have the authorities to allow any or all of the above to occur: (1) make reliability standards developed by NERC mandatory and enforceable; (2) backstop compliance determinations made by NERC and regional entities and allow disclosure of a provincial enforcement determination once that determination is made; (3) assure NERC's recovery of a fair allocation of reasonable costs of carrying out the purposes for which the electric reliability organization was formed. For those jurisdictions that do not possess the authority at this time to allow for any of the above to occur, NERC files today a "Notice of Filing of an Electric Reliability Organization." NERC is following this same approach with respect to its filings for reliability standards in Canada, filing Applications for Recognition in Provinces that have the authorities to make reliability standards developed by NERC mandatory and enforceable.

Commission, an Application for Recognition as the Electric Reliability Organization with the Provinces of Alberta, Nova Scotia, Ontario, and the National Energy Board, and a Notice of Filing as the Electric Reliability Organization with the Provinces of British Columbia, Manitoba, Québec, and Saskatchewan.

NERC submits the following information:

I. NOTICES AND COMMUNICATIONS

Notices and communications regarding this Notice may be addressed to:

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II. DESCRIPTION OF NERC

NERC Council is a New Jersey non-profit corporation whose members are the eight regional reliability councils currently in existence: Electricity Reliability Council of Texas ("ERCOT"), Florida Reliability Coordinating Council ("FRCC"), Midwest Reliability Organization ("MRO"), Northeast Power Coordinating Council ("NPCC"), Reliability*First* Corporation ("Reliability*First*"), Southeastern Electricity Reliability Council ("SERC"), Southwest Power Pool ("SPP"), and Western Electricity Coordinating Council ("WECC"). Since its formation in 1968, NERC Council has successfully operated as a self-regulatory organization ("SRO"), relying on reciprocity, and the mutual self-interest of owners, operators, and users of the bulk power system in order to achieve its mission of ensuring that the bulk electric system in North America is reliable, adequate, and secure.

NERC Corporation is also a New Jersey non-profit corporation and is an affiliate of NERC Council. NERC Corporation was formed for the sole purpose of becoming the ERO. NERC Corporation's members will be a broad body of electricity industry stakeholders and other entities interested in the reliability of the bulk power system in North America who elect to become members of NERC. Once NERC has been certified as the ERO by FERC, NERC Council, NERC Corporation, and the eight regional reliability councils intend to approve a plan pursuant to which NERC Council and NERC Corporation will be merged. NERC Corporation will be the surviving corporation following the merger and will assume the assets and liabilities of NERC Council. NERC Council will cease to exist. The certificate of incorporation and bylaws attached to the companion filing will be the certificate of incorporation and bylaws of the surviving corporation. NERC is following this approach because until such time as the new ERO is fully authorized, it is vital to the ongoing reliability of the bulk power system of North America that NERC Council continues to operate under its present corporate structure.

III. PROCESS FOR DEVELOPMENT OF RELIABILITY STANDARDS

NERC has diligently adhered to its standards development procedure, which has been certified by the American National Standards Institute ("ANSI") as being open, inclusive, balanced and fair. Owners, operators, and users of the bulk power system that must comply with the standards, as well as the end users who benefit from a reliable supply of electricity and the public in general, can be assured a standard is just, reasonable and not unduly discriminatory or preferential because the standards are developed through a procedure with the following attributes:

1. **Notice** — Public notice is given for all standards development actions.
2. **Openness and transparency** — Development of the standard is fully transparent and open to participation by all interested parties.
3. **Inclusiveness** — Fair consideration is given to every comment concerning a proposed standard.
4. **Balance and fairness** — Stakeholders approve the standard using a voting procedure that gives equal weight to each of nine voting segments representing the diverse interests of bulk power system owners, operators, and users, as well as end users and regulators. The segments are: transmission owners; regional transmission organizations, independent system operators, and regional reliability organizations; load-serving entities; transmission dependent utilities; electric generators; electricity brokers, aggregators, and marketers; large electricity end users; small electricity end users; and regulators and other governmental agencies.

> There is a high threshold for a quorum (three fourths of the ballot pool) and for approval (two thirds weighted average across the segments).

These provisions of NERC's standards development procedure ensure that substantial opportunity exists for all potentially affected parties to identify why they believe the proposed standard is or is not just and reasonable, or is or is not unduly discriminatory or preferential. By filing the archived record of development for each standard in Exhibit E, including the resolution of each objection, NERC will provide the evidence necessary to demonstrate that a standard is just, reasonable and not unduly discriminatory or preferential, at least as viewed by the affected parties.

A. Benchmarks of an Excellent Reliability Standard

To translate the goals stated above into objective measures, NERC proposes ten benchmarks for use in the recognition of reliability standards. NERC believes these benchmarks, described below, define the essential attributes of a technically sound reliability standard.

1. **Applicability —** Each reliability standard shall clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted. Such functional classes[3] include: reliability coordinators, balancing authorities, transmission operators, transmission owners, generator operators, generator owners, interchange authorities, transmission service providers, market operators, planning authorities, transmission planners, resource planners, load-serving entities, purchasing-selling entities, and distribution providers. Each reliability standard shall also identify

[3] These functional classes of entities are derived from NERC's reliability functional model. When a standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in Reliability Standards.

the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area. A standard may also identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 megawatts or greater, or transmission facilities energized at 200 kilovolts or greater.

2. **Purpose —** Each reliability standard shall have a clear statement of purpose that shall describe how the standard contributes to the reliability of the bulk power system.

3. **Performance Requirements —** Each reliability standard shall state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practice and the public interest. Each requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for bulk power system reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability —** Each performance requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement. Each performance requirement shall have one or more associated measures used to objectively evaluate compliance with the requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations —** Each reliability standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in the particular field.
6. **Completeness —** Reliability standards shall be complete and self-contained. The standards shall not depend on external information to determine the required level of performance.
7. **Consequences for Noncompliance —** In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, the consequences of violating a standard are clearly known to the responsible entities.
8. **Clear Language —** Each reliability standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practice, are able to arrive at a consistent interpretation of the required performance.
9. **Practicality —** Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.
10. **Consistent Terminology —** To the extent possible, reliability standards shall use a set of standard terms and definitions that are approved through the NERC reliability standards development process.

The information to justify that each standard meets these ten benchmarks is principally developed by evaluating the comments received from stakeholders during the development of the standard. The results of this evaluation are reviewed by the

Standards Committee prior to the standards being sent to the board for approval. In Section VI of this filing, NERC applies these benchmarks to demonstrate that the existing NERC reliability standards proposed for recognition either meet these requirements today or will meet them in a timely schedule described in the work plan provided in Section VII.

B. Impact of Reliability Standards on Competition

Consistent with NERC's historical focus on bulk power system reliability, NERC has already established mechanisms to avoid undue impacts on competition in the development of its reliability standards and will continue to do so as the ERO. As a fundamental tenet, NERC's standards development procedure requires due consideration of the impacts of standards on competition and ensures standards are not unduly discriminatory or preferential.

Many of the existing NERC standards are related to business practices, although their primary purpose is reliability. Reliability standards, business practices, and commercial interests are inextricably linked. An example of an existing standard that is both reliability standard and business practice is the Transmission Loading Relief Procedure currently used as an interconnection-wide congestion management method in the Eastern Interconnection. It would be safe to conclude that every reliability standard has some degree of commercial impact and therefore affects competition. The key concern is that the reliability standards not have an undue adverse effect on competition.

NERC has taken several steps to ensure its reliability standards do not have an undue adverse effect on business practices or competition. First, NERC coordinates the development of all standards with the North American Energy Standards Board

(NAESB) and the ISO/RTO Council through a memorandum of understanding and the work of the Joint Interface Committee. In addition to this formal process, NERC technical groups work informally with NAESB groups to ensure effective coordination of wholesale electric business practice standards and reliability standards. Recently NERC and NAESB established a procedure for the joint development of standards in areas that have both reliability and business practice elements and agreed to jointly publish the results to facilitate access by users of the standards.[4] This procedure is being implemented for all standards in which the reliability and business practice elements are closely related, thereby making joint development a more efficient approach.

To ensure each reliability standard does not have an undue adverse effect on competition, NERC requires that each standard meet the following criteria:

1. **Competition —** A reliability standard shall not give any market participant an unfair competitive advantage.
2. **Market Structures —** A reliability standard shall neither mandate nor prohibit any specific market structure.
3. **Market Solutions —** A reliability standard shall not preclude market solutions to achieving compliance with that standard.
4. **Commercially Sensitive Information —** A reliability standard shall not require the public disclosure of commercially sensitive information. All market

[4] The NERC-NAESB procedure allows the reliability and business practice components to be developed through each organization's respective standards process by a joint working group of experts. The result is a standard document that includes both reliability components and corresponding business practice components. The reliability components go through the NERC standards process and are filed with the appropriate governmental authority for approval. The NAESB components are shown in the NERC standard for information purposes.

participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.

IV. COMPETENCY AS AN ACCREDITED STANDARDS DEVELOPER

The proposed reliability standards provided in Exhibit A were developed by NERC, a competent, industry-based standards developer that is accredited by the American National Standards Institute ("ANSI").

A. NERC's Experience as a Standards Developer

NERC has been promoting and evaluating bulk power system reliability and developing reliability standards for almost 40 years. NERC was formed as a voluntary electric reliability organization shortly after the 1965 blackout in the northeastern United States and eastern Canada. Since its inception, NERC has adopted operating policies and planning standards to ensure the reliability of the bulk power system in North America.

In response to the blackout of August 2003, and anticipating an eventual transition to the ERO, NERC transformed its existing operating policies and planning standards into Version 0 reliability standards,[5] which became effective on April 1, 2005. These standards provide a comprehensive set of requirements for the reliable operation, planning, and design of bulk power systems. NERC has continued to improve these standards and recently approved 12 new standards.[6] The entirety of the 102 reliability standards provided in Exhibit A is a clear demonstration of NERC's capability to develop technically sound reliability standards for a reliable bulk power system.

B. ANSI-Accredited Open Standards Process

In anticipation of U.S. reliability legislation that would authorize the creation of an electric reliability organization, several years ago NERC moved from developing

[5] The Version 0 standards refer to 90 standards approved by the NERC board on February 7, 2005, that became effective on April 1, 2005. An urgent action cyber security standard (1200) had been approved for implementation since August 13, 2003. In all, the 91 standards in effect on April 1, 2005, included approximately 450 distinct performance requirements on bulk power system owners, operators, and users.
[6] On February 7, 2006, NERC approved 12 new standards and revisions to 10 existing standards.

standards through its technical committees to developing standards through an open process that allows direct participation by all stakeholders. The process is based on the principles of ANSI, which accredited NERC as a standards developer on March 24, 2003. NERC's process is based on building consensus for each standard among reliability stakeholders across nine stakeholder segments. NERC ensures its process is open, inclusive of all interested parties, balanced, and fair.

It may seem intuitive that a stakeholder-driven standards process would lead to difficulty developing and approving stringent standards that are needed for a reliable bulk electric system. The experience in the first few years of the ANSI-accredited process has been to the contrary: stakeholders have repeatedly demonstrated a willingness and ability to develop and approve tough new standards, with most of the standards being approved by wide margins. The due process and "consider every minority comment" approach has in fact improved the quality of standards compared to the historical approach of developing standards within a technical committee. Broader diversity of views has added technical rigor to the standards and is a hallmark of the open process.

C. Technical Expertise to Develop Standards

A cornerstone of NERC since its inception has been the direct participation of volunteer industry experts who are the front-line practitioners in their fields. At any point in time there are more than 2,500 individuals participating in various NERC groups and activities. Additionally, the regional councils collectively engage many more experts in support of programs and activities to promote reliable bulk power systems.

As is the case for most national and international technical standards development bodies, the NERC standards development procedure depends on teams of experts to develop the standards, combined with peer review of the standards through a public comment process. Each drafting team has ownership and control of the standard through the development phase, subject to oversight by the Standards Committee to assure that the ANSI-accredited process is being correctly followed and the drafting team has been diligent in addressing all comments on the proposed standards.

NERC currently has about 250 volunteer experts assigned to 20 different drafting teams. As a representative sample, Exhibit B includes the rosters of the five drafting teams that developed the standards proposed in Exhibit A for recognition. The rosters display an unparalleled depth and diversity of expertise that is well suited for the development of technically excellent standards.

To ensure the technical capabilities of each drafting team, the Standards Committee publicly solicits nominations for volunteer experts to work on each standard development project. Each project has a written set of qualifications and identified areas of expertise needed for the development of the standards. Sometimes a particular standard can require unique types of expertise. For example, the drafting team for standard FAC-003-1 — Transmission Vegetation Management Program, had more than a dozen experts, each with 15 to 35 years experience as certified arborists and forestry professionals. The Standards Committee reviews the qualifications of each candidate and appoints a drafting team that collectively has the expertise necessary to develop the particular standards assigned to the group. When gaps are noted in the necessary areas of expertise, the Standards Committee will follow with additional requests for volunteers and NERC staff will assist by recruiting individuals with known expertise in the missing areas.

An additional source of technical expertise applied in the development of reliability standards comes through peer review and comment on drafts of the standards authorization requests and the proposed standards.

The existing NERC reliability standards development procedure, which engages industry experts on standards drafting teams, provides the best possible approach to harnessing the technical expertise of industry in the development of reliability standards. Experience thus far demonstrates that the process works well because the drafting teams and the industry as a whole are committed to strong standards that hold bulk power system owners, operators and users accountable for reliability.

D. Standards Development Due Process

All of the Version 0 and new standards provided in Exhibit A were developed and approved using NERC's open standards process. NERC's current standards development procedure explicitly provides for reasonable notice and opportunity for public comment, due process, openness and balance of interests. Version 4 of the Reliability Standards Process Manual is provided in Exhibit C and is representative of the procedures that were applied to develop the standards in Exhibit A. [7]

One recommendation from the August 2003 northeast blackout was for NERC to streamline its standards development process. That effort recently culminated in major revisions and improvements to the standards process. The revised procedure allows an urgent action standard to be approved by stakeholders and the NERC board within 60 days of receiving a proposal. A regular standard could be developed and approved in as

[7] Version 4 of the procedure manual became effective on August 2, 2005. The major change from prior versions was to streamline and clarify the standards process. All of the standards in Exhibit A were developed essentially through the same due process, albeit there were different versions of the standards procedure in effect at different times.

little as four months; however, more complex standards requiring development of new technical concepts, methods and measures can take 12 to 15 months.

NERC's standards development procedure has the following principal attributes of due process:

- Any member or committee of NERC, any member or committee of a regional entity, or any person or entity directly and materially affected by the reliability of the North American bulk power system may propose a reliability standard, revision to a standard, or withdrawal of a standard.
- NERC publicly notices each standard request and receives comment on the scope and justification for the proposed standard for a 30-day period. Notice of proposed standard provides an opportunity for participation by all persons that may be directly and materially affected.
- Once there is consensus on the scope and justification for the proposed standard, the Standards Committee authorizes development of the standard and appoints a drafting team.
- The drafting team applies their engineering and operating expertise to draft the standard based on sound technical criteria.
- Draft standards are posted for public comment for a 45-day period. If, based on comments received, the drafting team believes it can substantively improve a standard and increase consensus for a standard, the drafting team will revise the draft standard and post it again for comment. This step may be repeated, although experience indicates that even the most complex standards converge within two or

three postings. More narrowly defined projects can be completed with a single posting for comment.

- Each standard is reviewed to determine if field testing is necessary. Typically field testing is required when new engineering or operational methods are proposed that have not been validated through practical experience. There are several field tests in progress[8], but none of the standards proposed in Exhibit A required a field test.[9]
- Once the drafting team has addressed all stakeholder comments and determined the standard would not be substantively improved by seeking further comment, the drafting team recommends the standard for a ballot of the stakeholders. The Standards Committee authorizes a ballot of the standard once it has verified the drafting team has met all of the procedural requirements and fairly considered all comments. The Standards Committee will remand the draft standard to the drafting team if the drafting team did not satisfactorily complete the process or did not sufficiently consider the inputs of commenters. Conversely, the drafting team may at any time conclude there is no consensus for the standard and recommend the Standards Committee terminate the development of the standard.
- A ballot pool for the proposed standard is formed at least 30 days prior to the start of the ballot and is open to all interested parties that have joined the Registered Ballot Body to vote on standards.

[8] Standards currently in field testing include: organization certification standards, balancing resources and demand standards, and generator reactive capability verification standards.

[9] Because the Version 0 standards were a translation of prior policies and practices, no field tests were required. The 12 new standards were reviewed for practicality of implementation and were deemed to not require field testing before implementation.

- Approval of a new reliability standard or revision to an existing reliability standard requires a quorum of at least 75 percent of the members of the ballot pool and a two-thirds majority of the weighted segment votes in the affirmative. The use of a weighted segment voting calculation ensures that there is a "balance of interests in the development and approval of reliability standards" among the nine stakeholder segments. The use of a supermajority for approval ensures strong support for the standard.
- If there are any negative votes in the first ballot with reasons specified, the ballot pool will be presented an opportunity to change or add a vote during a second 10-day ballot period. The reasons given for the negative votes on the first ballot, and the responses of the drafting team, are presented to the members of the ballot pool to allow them to reconsider their vote based on objections given on the first vote. This ensures that all objections are heard and considered before approval of a standard.[10]
- New reliability standards or revisions to reliability standards approved by the ballot pool are submitted to the Board of Trustees for approval. The Board must adopt or reject a proposed standard and may not modify a proposed standard. If the Board chooses not to adopt a proposed standard, it must provide its reasons for not doing so. NERC's bylaws require that the board has within its membership sufficient technical expertise to provide oversight of technical matters of NERC, including the development of standards.

[10] This so-called "recirculation" ballot is a requirement of ANSI accreditation for the purpose of ensuring no person's views are excluded from consideration in the approval of a standard.

- All standards development activities, including meetings of the drafting teams and the Standards Committee, are open.
- All standards actions are publicly noticed and drafts of standards, comments received, and responses to comments are publicly posted and become a permanent part of the development record for each standard. Exhibit E provides the complete development records for all standards filed for approval in Exhibit A.
- Each standard is subject to appeal in the event an entity has a substantive or procedural complaint regarding the development, approval, revision, reaffirmation or withdrawal of a reliability standard. The appeals procedure is provided in the Reliability Standards Process Manual. There were no appeals related to the standards in Exhibit A and no appeals of standards actions have been initiated in the nearly four years the process has been in existence.
- The Standards Committee, a body elected by the stakeholder segments,[11] provides oversight of the reliability standards development process to ensure stakeholder interests are fairly represented.

[11] The Standards Committee is a representative committee consisting of two representatives that are democratically elected by each of the nine stakeholder segments. Additionally, there is a requirement that at least two of the members are Canadian.

V. SUMMARY OF RELIABILITY STANDARDS

This section provides a summary of NERC's existing reliability standards, which are presented in Exhibit A.

A. NERC Filing of All Proposed Reliability Standards

NERC is filing the entirety of its existing reliability standards concurrently with its Notice of Filing as the ERO for several reasons. Having the existing standards approved or recognized by governmental authorities in the United States and Canada will reinforce the importance of these standards and will have an immediate positive benefit with regard to the reliability performance of all bulk power system owners, operators, and users that come under the new reliability authorities of FERC and the governmental authorities in Canada.

Building from the existing body of standards also provides continuity from the current reliability regime and avoids any potential gaps in accountability for reliable operation of the bulk power system that would occur if only a portion of the standards was approved and made mandatory. Initially approving a partial set of standards at the onset of ERO operations would have the effect of reducing the scope of existing reliability requirements and risk the possibility of a major system failure for which the cause is not related to an approved standard.

Initially approving a partial set of standards could also have the effect of creating a patchwork of standards that are in effect in some jurisdictions in North America, but not all. Finally, NERC's existing standards are the best available today in North America and represent decades of work to document necessary practices to ensure a reliable bulk power system. The work plan provided in Section VII defines an initial set of tasks to be completed in 2006. The plan also outlines future work for continuing to improve the standards.

B. Overview of Reliability Standards

NERC has approved the 102 standards provided in Exhibit A for implementation in the NERC compliance program. These standards are summarized below.

The standards submitted in this Notice represent a composite of standards with three different origins:

- One standard, the urgent action cyber security standard known as "1200" was initially approved in August 2003 and was twice extended[12]. The standard is set to be replaced by a comprehensive set of eight new cyber security standards. The new standards have been approved by ballot of the stakeholders and are pending adoption by the NERC Board of Trustees on May 2, 2006. NERC will file the replacement standards immediately following board approval. For that reason, NERC requests deferral of the evaluation of the 1200 cyber security standard at this time, pending the filing of the new replacement cyber security standards no later than May 15, 2006. The 1200 cyber security standard is provided in Exhibit A for information purposes at this time.
- 90 of the standards in Exhibit A are the so-called "Version 0" standards that became effective on April 1, 2005. These standards are a translation, with certain improvements, of NERC's operating policies that were developed over several decades and its planning standards, which were approved in September 1997. Of these 90 standards, one was modified in August 2005 and ten more were modified

[12] By procedure, an urgent action standard expires automatically after one year, although extensions may be approved by stakeholder vote and board approval. Automatic expiration encourages speedy development of a permanent replacement standard through the full due process.

in February 2006 when NERC adopted revisions that had been approved by stakeholder ballot. The most recent version of each of these standards is provided in Exhibit A.

- In February 2006, NERC also approved 12 new standards for implementation. Those standards are included in this filing. Some of these standards address 2003 blackout recommendations and others expand the set of standards in other areas.

During 2006, subject to approval by stakeholders and the NERC Board of Trustees, additional standards are planned for completion. NERC will file these additional standards as they are completed, noting any instances in which the new standards replace or modify the standards proposed in Exhibit A. For planning purposes, a list of standards that are scheduled to become available for consideration in 2006 is provided in Section VII.

Collectively, the 102 existing standards define overall acceptable performance with regard to the operation, planning, and design of the North American bulk power systems. The standards address a full range of reliability objectives, including: real-time balancing of generation with demand to maintain frequency at 60 hertz; operating equipment within thermal, voltage and stability limits; operating to withstand the failure of any single facility and to avoid cascading failures following credible multiple contingency events; vegetation management in transmission rights-of-way; critical infrastructure protection; voice and data communications; relay protection for both generators and transmission equipment; system modeling and analysis; under frequency load shedding; emergency planning including system black start and restoration; and personnel training and certification.

The NERC standards process also makes allowance for appropriate regional differences. There are currently seven such regional differences, each of which has been incorporated into and made a part of the NERC standards. These are instances in which a region has requested an alternative approach to meeting a reliability objective addressed by a NERC standard. They fall into three categories: 1) interconnection-wide differences dictated by the electric characteristics of the interconnection; 2) interconnection-wide differences reflecting common practice across the interconnection; and 3) an allowance for a FERC-approved regional transmission organization to operate within its tariff and market protocols. Each of these differences is noted in the detailed description of the standards below.

C. Detailed Description of Proposed Reliability Standards

The standards in Exhibit A are grouped by topical area.[13] The proposed standards are summarized as follows:

- **Balancing Resources and Demand (BAL) —** balancing resources and demand to maintain interconnection frequency within limits:
  - **BAL-001-0 Real Power Balancing Control Performance (implemented April 1, 2005) —** Maintains interconnection frequency by setting the balancing authority's limits for balancing real power (MW) demand and supply during steady-state conditions. NERC refers to these limits as control performance measures 1 and 2. ERCOT has a regional variance

[13] NERC reliability standards are numbered with a three-character alphanumeric designation of a topical area (e.g., BAL represents balancing of generation and demand). This is followed by the standard number within that topical area, e.g., 002. The final number represents the version of the standard, e.g., version "0" or version "1", etc.

for this standard because certain aspects of the standard do not apply to an interconnection that operates as a single balancing area.

- **BAL-002-0 Disturbance Control Performance (implemented April 1, 2005) —** Maintains interconnection frequency by setting the balancing authority’s limit for balancing real power (MW) demand and supply following the sudden failure of generation. NERC refers to this limit as the disturbance control measure.
- **BAL-003-0 Frequency Response and Bias (implemented April 1, 2005) —** Maintains interconnection frequency by a) ensuring that the balancing authority's secondary (automatic generation) control allows its primary (governor) control to help stabilize interconnection frequency changes that are caused by control errors in *other* balancing authority areas, and b) ensuring that the balancing authority’s bias setting is appropriately matched to its actual frequency response (governor plus load response).
- **BAL-004-0 Time Error Correction (implemented April 1, 2005) —** Minimizes the interconnection’s long-term energy imbalance by reducing the time error. Interconnection energy imbalance is reflected moment-to-moment as the difference between the actual interconnection frequency and scheduled frequency, typically 60 hertz. Over time, this frequency error accumulates as a time error — the difference between interconnection time (i.e., as seen on an analog clock plugged into the electric system) and the National Institute of Standards and Technology standard time. Therefore, correcting the interconnection time error

(periodically increasing or decreasing generation to return the accumulated time error back to zero) is also a method for correcting the long-term energy imbalance between generation and demand.

- **BAL-005-0 Automatic Generation Control (implemented April 1, 2005) —** Maintains interconnection frequency by a) requiring that all generation, transmission, and customer load be within the metered boundaries of a balancing authority area, and b) establishing the functional requirements for the balancing authority's regulation service, including its calculation of Area Control Error (ACE).
- **BAL-006-0 Inadvertent Interchange (implemented April 1, 2005) —** Minimizes the balancing authority's and interconnection's long-term energy imbalance by establishing balancing authority interchange accounting procedures. These procedures include checking hourly actual and scheduled interchange with adjacent balancing authorities, and maintaining on- and off-peak accounts. (Related North American Energy Standards Board business practices define the on- and off-peak periods). The Midwest Independent System Operator (MISO) has a variance for this standard to allow MISO to manage inadvertent payback on behalf of its member balancing areas.

• **Critical Infrastructure Protection (CIP) —** provide critical infrastructure protection, including cyber security protection and sabotage reporting:

- **1200 Urgent Action Cyber Security (implemented August 13, 2003 and extended twice through August 13, 2006 – <u>Filed for information</u>**

only, pending submittal of replacement standards no later than May 15, 2006) — Ensures transmission reliability through protection from cyber attacks by requiring the identification and documentation of the critical cyber assets and certain measures to protect those assets from cyber intrusion.

- **CIP-001-0 Sabotage Reporting (implemented April 1, 2005) —** Ensures that operating entities inform each other about sabotage of the bulk power system. The standard also requires that these entities establish contacts and sabotage reporting procedures with the U.S. Federal Bureau of Investigation and the Royal Canadian Mounted Police as applicable.

- **Communications (COM) —** provide communications for interconnected operations:
  - **COM-001-0 Telecommunications (implemented April 1, 2005) —** Ensures coordinated telecommunications among operating entities, which is fundamental to maintaining grid reliability. Establishes general telecommunications requirements for operating entities, including equipment testing and coordination. This standard also establishes English as the common language between and among operating personnel, and sets policy for using the NERCnet telecommunications system.
  - **COM-002-1 Communications and Coordination (effective November 1, 2006, replacing COM-002-0) —** Provides more detail on the communications requirements between and among operating entities. The

standard also lists specific situations that require communications with other operating entities.

- **Emergency Operations (EOP) —** be prepared for emergencies, including load-shedding and system restoration:
  - **EOP-001-0 Emergency Operations Planning (implemented April 1, 2005) —** Ensures coordinated operations during emergency conditions, such as insufficient generating resources, transmission emergencies (for example, transmission overloads or lack of reactive supply), and system restoration after a grid failure. This standard requires that balancing authorities and transmission operators have emergency telecommunications facilities and protocols in place, and emergency operating plans, including emergency energy transfers (interchange), and fuel deliveries.
  - **EOP-002-1 Capacity and Energy Emergencies (effective November 1, 2006, replacing EOP-002-0) —** Ensures energy balance in the interconnection during emergency conditions. The standard requires the balancing authority to have the authority to bring all necessary generation on line, communicate its energy and capacity emergency with its reliability coordinator, and coordinate with other balancing authorities. Furthermore, the standard limits a balancing authority's use of the other balancing authorities' bias contribution to the interconnection ("leaning on the ties.")

- **EOP-003-0 Load Shedding Plans (implemented April 1, 2005) —** Ensures energy balance and reliable transmission operations during emergency conditions through load shedding when all other remedial steps have been ineffective. The standard requires the balancing authority and transmission operator to have plans for automatic load shedding for underfrequency or undervoltage, and requires the balancing authority and transmission operator to shed load to avoid the risk of uncontrolled, cascading failure of the interconnection. While load shedding is usually a "last resort," the ability to reduce demand through these controlled steps is fundamental to either a) maintain energy balance within acceptable limits, or b) remain within system operating limits and interconnection reliability operating limits.
- **EOP-004-0 Disturbance Reporting (implemented April 1, 2005) —** Establishes requirements for reporting system disturbances to the regional reliability organization and NERC for lessons learned and analysis. This standard is linked to the U.S. Department of Energy disturbance reporting requirements and EIA Form 417.
- **EOP-005-0 System Restoration Plans (implemented April 1, 2005) —** Ensures that plans, procedures, and resources are available to restore the electric system to a normal condition in the event of a partial or total shut down of the system. Specifically, this standard requires the transmission operator, balancing authority, and reliability coordinator to have effective restoration plans, test those plans, and be able to restore the

interconnection following a blackout. This standard also requires operating personnel to be trained in these plans.

- **EOP-006-0 Reliability Coordination - System Restoration (implemented April 1, 2005)** — Provides specific requirements for reliability coordinators during a system restoration.
- **EOP-007-0 Establish, Maintain, and Document a Regional Blackstart Capability Plan (implemented April 1, 2005)** — Ensures that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in the overall coordinated regional system restoration plans.
- **EOP-008-0 Plans for Loss of Control Center Functionality (implemented April 1, 2005)** — Ensures a plan to continue reliable operations and maintain situation awareness when a reliability coordinator's, balancing authority's, or transmission operator's control center is no longer operable.
- **EOP-009-0 Documentation of Blackstart Generating Unit Test Results (implemented April 1, 2005)** — Ensures that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated regional system restoration plans.

- **Facilities (FAC)** — determine facility connection requirements, facility ratings, system operating limits, and transfer capabilities; maintain equipment and rights-of-way, including vegetation management:

- **FAC-001-0 Facility Connection Requirements (implemented April 1, 2005) —** Ensures transmission owners establish facility connection and performance requirements to avoid adverse impacts to the bulk power system.
- **FAC-002-0 Coordination of Plans for New Facilities (implemented April 1, 2005) —** Ensures generator owners, transmission owners and bulk power system users meet facility connection and performance requirements to avoid adverse impacts on reliability.
- **FAC-003-1 Vegetation Management Program (effective April 7, 2006, replacing FAC-003-0) —** Minimizes transmission outages from vegetation located on or near transmission rights-of-way (ROW) by maintaining safe clearances between transmission lines and vegetation, and establishes a system for uniform reporting of vegetation-related transmission outages. Applies to 200 kV or higher voltage transmission lines (and lower voltage transmission lines determined to be critical to reliability by the regional reliability organizations). Requires each transmission owner to have a documented vegetation management program in place, including records of its implementation. Each program must be designed for the geographical area and specific design configurations of the transmission owner's system.
- **FAC-008-1 Facility Ratings Methodology (effective August 7, 2006, replacing FAC-004-0) —** Sets minimum criteria and elements to be

considered in the determination of facility ratings, as needed to plan and operate the bulk power system.

    - **FAC-009-1 Establish and Communicate Facility Ratings (effective October 10, 2006, replacing FAC-005-0) —** Requires disclosure and peer review of the methods used to determine facility ratings to ensure ratings are verified and known to others with a reliability need.
    - **FAC-012-1 Transfer Capabilities Methodology (effective August 7, 2006, new) —** Sets minimum criteria and elements to be considered in the determination of transfer capabilities, as needed to plan and operate the bulk power system.
    - **FAC-013-1 Establish and Communicate Transfer Capabilities (effective October 7, 2006, new) —** Requires disclosure and peer review of the methods used to determine transfer capabilities to ensure transfer capabilities are verified and known to others with a reliability need.

- **Interchange (INT) —** schedule and coordinate uses of the bulk power system:
    - **INT-001-0 Interchange Transaction Tagging (implemented April 1, 2005) —** Ensures uses of the bulk power system are known to operating entities and reliability coordinators for the purpose of evaluating reliability impacts and curtailing uses in the event the system becomes overloaded. Tagging provides a) information that balancing authorities need to physically move the energy associated with the transactions arranged between market participants, and b) information that reliability coordinators need to determine which transactions to curtail to mitigate a

system operating limit or interconnection reliability operating limit. The Western Electricity Coordinating Council (WECC) has a regional variance exempting the tagging of dynamic schedules and inadvertent payback. MISO has an entity variance to allow MISO to provide market flow information in lieu of tagging intra-market flows among its member balancing authorities.

- **INT-002-0 Interchange Transaction Tag Communication and Assessment (implemented April 1, 2005) —** Ensures energy interchange transaction information is exchanged among reliability entities and evaluated for reliability impacts. Defines communications and status of tags and how balancing authorities and transmission service providers evaluate and approve or deny transactions. MISO and the Southwest Power Pool (SPP) have variances to allow market participants to utilize a scheduling agent to prepare transaction tags on their behalf. MISO has a variance to allow an enhanced single point of contact scheduling agent.

- **INT-003-0 Interchange Transaction Implementation (implemented April 1, 2005) —** Ensures energy balance in the interconnection by establishing standard balancing authority "ramp" rates and start and stop times for bilateral interchange transactions. Balancing authorities implement bilateral interchange transactions by raising generation levels (to send) or lowering generation levels (to receive). Generators cannot instantly change their output; rather they must do so gradually, which is called "ramping." This standard also ensures that balancing authorities adhere to transfer limits, that interchange may be scheduled only between adjacent balancing authorities, and that balancing authorities coordinate with transmission operators when transactions are scheduled across dc ties. MISO and the Southwest Power Pool (SPP) have regional variances to allow market participants to utilize a scheduling agent to prepare transaction tags on their behalf. MISO has an entity variance to allow MISO to provide market flow information in lieu of tagging intra-market flows among its member balancing authorities. MISO has a variance to allow an enhanced single point of contact scheduling agent.

- **INT-004-0 Interchange Transaction Modifications (implemented April 1, 2005)** — Ensures energy balance and reliable transmission operations during emergency conditions by adjusting interchange transactions. Requires the sink balancing authority (where the load or end user is located) to communicate any change in the transaction. Ensures tags for dynamic schedules, which are transactions that vary from hour to hour, are updated. WECC has a regional variance exempting the tagging of dynamic schedules and inadvertent payback.

- **Reliability Coordination (IRO)** — coordinate interconnected operations, including interconnection limits and interconnection-wide transmission loading relief or congestion management:
  - **IRO-001-0 Reliability Coordination – Responsibilities and Authorities (implemented April 1, 2005)** — Ensures energy balance and reliable transmission operations by establishing and listing the basic rules for

reliability coordinators. This standard also requires reliability coordinators to have a) a reliability plan; b) the responsibility and authority to act; and c) clear rules for delegating tasks to others. Finally, the standard requires other operating entities to follow the reliability coordinator's directives.

- **IRO-002-0 Reliability Coordination – Facilities (implemented April 1, 2005)** — Establishes the monitoring, analysis, and communications facilities that reliability coordinators must have to perform their tasks.
- **IRO-003-1 Reliability Coordination – Wide Area View (effective August 1, 2006, replacing IRO-003-0)** — Ensures reliability coordinators maintain a wide enough view to be able to maintain situation awareness across a wide area of the interconnection and calculate system operating limits and interconnection reliability operating limits.
- **IRO-004-1 Reliability Coordination – Operations Planning (effective November 1, 2006, replacing IRO-004-0)** — Ensures energy balance and transmission reliability over (typically) the next 24 hours. Operations planning requires an up-to-date model of the bulk power system (with its attendant data requirements), studies to determine potential system operating limits and interconnection reliability operating limits, and the ability to share the study results and resulting operating plans.
- **IRO-005-1 Reliability Coordination – Current Day Operations (effective November 1, 2006, replacing IRO-005-0)** — Ensures energy

balance and transmission reliability for the current day by identifying the tasks that reliability coordinators must perform throughout the day.

- **IRO-006-1 Reliability Coordination – Transmission Loading Relief (implemented August 8, 2005, replacing IRO-006-0)** — Ensures the reliability coordinator has a coordinated method to offload the transmission system if it becomes congested in order to avoid limit violations. The reliability coordinator may invoke either a "local" transmission curtailment plan, or an interconnection-wide plan, to mitigate system operating limit or interconnection reliability operating limit violations. Each interconnection is required to have an interconnection-wide plan. MISO and the PJM Interconnection, LLC (PJM) have a regional variance for reporting of market flow information to the Interchange Distribution Calculator[14], rather than tagged transaction information. ERCOT and WECC have separate interconnection-wide congestion management methods that are addressed outside the NERC standard.

- **IRO-014-1 Procedures to Support Coordination between Reliability Coordinators (effective November 1, 2006, new)** — Ensures energy balance and transmission reliability by requiring reliability coordinators to have operating procedures to a) exchange operating information, and b) coordinate operating actions. Examples of operating actions include

[14] The Interchange Distribution Calculator (IDC) is a congestion management program used to coordinate transmission loading relief in the Eastern Interconnection, in accordance with the Transmission Loading Relief Procedure established as Attachment 1 in reliability standard IRO-006. PJM and MISO are allowed to submit market flow information to the IDC because it would not be practical or beneficial to apply interchange transaction tags to power flows internal to a market.

requiring balancing authorities to adjust generation to maintain their area control error within limits or provide additional reactive power, reduce or curtail interchange to stay within system operating limits or interconnection reliability operating limits, or shed load.

- **IRO-015-1 Notifications and Information Exchange between Reliability Coordinators (effective November 1, 2006, new) —** Ensures energy balance and transmission reliability by requiring reliability coordinators to share information regarding their operating procedures and plans with other reliability coordinators.
- **IRO-016-1 Coordination of Real-time Activities between Reliability Coordinators (effective November 1, 2006, new) —** Ensures energy balance and transmission reliability by requiring reliability coordinators to coordinate their real-time operating activities with one another. Requires that reliability coordinators to work with one another to solve operating problems and resolve any disagreements. The standard also requires that the reliability coordinator maintain records (logs) of their actions.

- **Modeling (MOD) —** model system performance for planning, reliability assessment and analysis, and forecasting:
  - **MOD-001-0 Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies (implemented April 1, 2005) —** Ensures transmission reliability by requiring the regional reliability organizations to develop methods for determining total transfer capability and available transfer capability. The

standard specifies nine parameters that must be included in the available transfer capability and total transfer capability calculation methods, and requires the regional reliability organizations to post these methods.

- **MOD-002-0 Review of Total Transfer Capability and Available Transfer Capability Calculations and Results (implemented April 1, 2005)** — Ensures transmission reliability by requiring the regional reliability organizations to review their total transfer capability and available transfer capability calculations at least annually to ensure that those calculations comply with the regional reliability organization's methods as specified in MOD-001. The standard also requires the regional reliability organization to provide the results of these reviews to NERC.
- **MOD-003-0 Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values (implemented April 1, 2005)** — Ensures transmission reliability by requiring the regional reliability organizations to provide a procedure for submitting questions about total transfer capability and available transfer capability calculation methods to the transmission service providers. Accurate total transfer capability and available transfer capability calculations help keep the transmission system within its system operating limits or interconnection reliability operating limits in real time.
- **MOD-004-0 Documentation of Regional Capacity Benefit Margin Methodologies (implemented April 1, 2005)** — Ensures transmission

reliability by requiring the transmission service providers to calculate the transmission capability, called the capacity benefit margin, that is needed to carry emergency generation. The standard requires the regional reliability organizations to provide the procedure for determining capacity benefit margin values. The standard specifies ten parameters that the procedure must include, and requires the regional reliability organizations to post these procedures.

- **MOD-005-0 Procedure for Verifying Capacity Benefit Margin Values (implemented April 1, 2005) —** Requires the regional reliability organizations to review their transmission service providers' capacity benefit margin values at least annually to ensure that those values comply with the regional reliability organization's methods as specified in MOD-004. The standard specifies four requirements of the review procedure, and requires the regional reliability organization to provide the results of these reviews to NERC.
- **MOD-006-0 Procedures for Use of Capacity Benefit Margin Values (implemented April 1, 2005) —** Ensures transmission service providers provide the procedures for using capacity benefit margin, and that the procedures address specific requirements.
- **MOD-007-0 Documentation of the Use of Capacity Benefit Margin (implemented April 1, 2005) —** Ensures transmission service providers report the use of capacity benefit margin.

- **MOD-008-0 Documentation and Content of Each Regional Transmission Reliability Margin Methodology (implemented April 1, 2005) —** Ensures transmission service providers calculate transmission reliability margin and incorporate five "uncertainties" in the transmission reliability margin calculation. Requires the regional reliability organizations to provide a procedure for determining transmission reliability margin values, and requires the regional reliability organizations to post these procedures.
- **MOD-009-0 Procedure for Verifying Transmission Reliability Margin Values (implemented April 1, 2005) —** Ensures transmission service providers' transmission reliability margin values are reviewed at least annually. The standard specifies four requirements of the review procedure, and requires the regional reliability organization to provide the results of these reviews to NERC.
- **MOD-010-0 Steady-State Data for Transmission System Modeling and Simulation (implemented April 1, 2005) —** Ensures data are available for reliability analysis and studies by requiring transmission owners, transmission planners, generator owners, and resource planners to provide information for steady-state system modeling.
- **MOD-011-0 Regional Steady-State Data Requirements and Reporting Procedures (implemented April 1, 2005) —** Ensures that transmission owners, transmission planners, generator owners, and resource planners within each interconnection are using consistent data specifications,

information exchange, and modeling techniques to simulate the bulk power system in its steady state.

- **MOD-012-0 Dynamics Data for Transmission System Modeling and Simulation (implemented April 1, 2005)** — Ensures data are available for reliability analysis and studies by requiring transmission owners, transmission planners, generator owners, and resource planners to provide information for dynamic system modeling.
- **MOD-013-0 Regional Reliability Organization Dynamics Data Requirements and Reporting Procedures (implemented April 1, 2005)** — Ensures that transmission owners, transmission planners, generator owners, and resource planners within each interconnection are using consistent data specifications, information exchange, and modeling techniques to simulate the dynamic behavior of the bulk power system. System models enable planners to simulate how a portion (or even all) of the interconnection will react to various perturbations — specifically, whether these perturbations result in the bulk power system stabilizing at a new point of equilibrium, or becoming unstable.
- **MOD-014-0 Development of Interconnection-Specific Steady State System Models (implemented April 1, 2005)** — Establishes consistent data requirements, reporting procedures, and steady state system models to be used in the analysis of the reliability of the interconnected transmission systems.

- **MOD-015-0 Development of Interconnection-Specific Dynamics System Models (implemented April 1, 2005) —** Establishes consistent data requirements, reporting procedures, and dynamic system models to be used in the analysis of the reliability of the interconnected transmission systems.
- **MOD-016-0 Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management (implemented April 1, 2005)**
- **MOD-017-0 Aggregated Actual and Forecast Demands and Net Energy for Load (implemented April 1, 2005)**
- **MOD-018-0 Reports of Actual and Forecast Demand Data (implemented April 1, 2005)**
- **MOD-019-0 Forecasts of Interruptible Demands and DCLM Data (implemented April 1, 2005)**
- **MOD-020-0 Providing Interruptible Demands and DCLM Data (implemented April 1, 2005)**
- **MOD-021-0 Accounting Methodology for Effects of Controllable Demand-Side Management in Forecasts (implemented April 1, 2005)** — Collectively, standards MOD-016 to MOD-021 ensure actual demand data are available for assessments of present and future performance and validation of past events and system modeling databases. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition,

to assist in proper real-time operating, load information related to controllable demand-side management programs is needed.

- **MOD-024-1 Verification of Generator Gross and Net Real Power Capability (Effective April 1, 2006 and January 1, 2007, new) —** Ensures transmission reliability by requiring generator owners to provide generator gross and net real power capability to generator operators, transmission operators, planning authorities, and transmission planners. The standard explains that the regional reliability organization will provide the procedure to verify these generator capabilities. These parameters are needed to properly model the bulk power system in its steady state.
- **MOD-025-1 Verification of Generator Gross and Net Reactive Power Capability (Effective January 1, 2007, new) —** Ensures transmission reliability by requiring generator owners to provide generator gross and net reactive power capability to generator operators, transmission operators, planning authorities, and transmission planners. The standard explains that the regional reliability organization will provide the procedure to verify these generator capabilities. These parameters are needed to properly model the bulk power system in its steady state. (See MOD-11)

- **Personnel (PER) —** provide qualified and trained operating personnel:
  - **PER-001-0 Operating Personnel Responsibility and Authority (implemented April 1, 2005) —** Ensures energy balance and transmission

reliability by requiring that transmission operator and balancing authority personnel to have the responsibility and authority to direct actions in real-time. In other words, operating personnel who are *responsible* for operating the bulk power system must have the *authority* to take action when they believe it is necessary.

- **PER-002-0 Operating Personnel Training (implemented April 1, 2005)** — Ensures that transmission operator and balancing authority personnel are adequately trained to accomplish the tasks for which they are responsible. The goal of a training program is to ensure that operating personnel are competent at performing their tasks. This standard also requires that operating personnel receive at least 5 days training annually in emergency operations.

- **PER-003-0 Operating Personnel Credentials (implemented April 1, 2005)** — Ensures that reliability coordinator, transmission operator, and balancing authority operating personnel are certified to perform the tasks for which they are responsible. Through a separate program, NERC provides certification tests for operating personnel.

- **PER-004-0 Reliability Coordination – Staffing (implemented April 1, 2005)** — Ensures that reliability coordinator personnel are adequately trained and certified. The standard requires that the reliability coordinator personnel are familiar with the area of the bulk power system over which they are responsible. This includes knowing the transmission operators, generator operators, and balancing authorities, their operating practices and procedures, and their system operating limits and interconnection reliability operating limits.

- **Protection and Control (PRC)** — install and maintain system protection equipment, including under-frequency load shedding and, where applicable, under-voltage load shedding:
    - **PRC-001-0 System Protection Coordination (implemented April 1, 2005)** — Ensures that protection systems are coordinated among operating entities by requiring transmission operators and generator operators to notify appropriate entities of relay or equipment failures that could impact system reliability, and to coordinate with appropriate entities when new or protection systems are installed or when existing protection systems are modified.
    - **PRC-002-0 Define and Document Disturbance Monitoring Equipment Requirements (implemented April 1, 2005)** — Ensures that disturbance monitoring equipment is installed uniformly to facilitate development of models and analyses in the event of a system disturbance by requiring the regional reliability organization to establish comprehensive requirements for the installation of disturbance monitoring equipment.
    - **PRC-003-1 Regional Procedure for Transmission Protection System Misoperations (effective May 1, 2006, replacing PRC-003-0)** — Ensures that all transmission and generation protection system misoperations are analyzed, and corrective action plans are developed by requiring the regional reliability organization to develop a procedure for

the monitoring and review of misoperations of the protection systems and the development and documentation of corrective actions.

- **PRC-004-1 Analysis and Mitigation of Transmission and Generation Protection System Misoperations (effective August 1, 2006, replacing PRC-004-0) —** Ensures that all transmission and generation protection system misoperations affecting the reliability of the bulk power system are analyzed and mitigated by requiring the protection system owners to analyze and document protection system misoperations and develop corrective actions plans in accordance with the regional reliability organization's procedures.
- **PRC-005-1 Transmission and Generation Protection System Maintenance and Testing (effective May 1, 2006, replacing PRC-005-0) —** Ensures that all transmission and generation protection systems affecting the reliability of the BES are maintained and tested by requiring the protection system owners to develop, document, and implement a protection system maintenance program that may be reviewed by the regional reliability organization.
- **PRC-006-0 Development and Documentation of Regional Underfrequency Load Shedding Programs (implemented April 1, 2005) —** Ensures the development of a regional underfrequency load shedding program to be used as a last resort to preserve the bulk power system during a major system failure that could cause system frequency to collapse. Requires the regional reliability organization to develop,

coordinate, document, and assess underfrequency load shedding program design and effectiveness at least every five years.

- **PRC-007-0 Assuring Consistency with Regional Underfrequency Load Shedding Programs (implemented April 1, 2005) —** Ensures the implementation of an underfrequency load shedding program by requiring entities identified by regional reliability organization studies to ensure the entity's underfrequency load shedding program meets the requirements of the regional program and to provide underfrequency load shedding data to the regional reliability organization.
- **PRC-008-0 Underfrequency Load Shedding Equipment Maintenance Programs (implemented April 1, 2005) —** Ensures that underfrequency load shedding systems are maintained by requiring the owners of such systems to document and implement a maintenance and testing program that may be reviewed by the regional reliability organization.
- **PRC-009-0 Underfrequency Load Shedding Performance Following an Underfrequency Event (implemented April 1, 2005) —** Ensures that the performance of an under frequency load shedding system is analyzed and documented following an underfrequency event by requiring the owner or operator of an underfrequency load shedding system to document its operation in accordance with the regional reliability organization's program.
- **PRC-010-0 Assessment of the Design and Effectiveness of UVLS Program (implemented April 1, 2005) —** Ensures that undervoltage load

shedding programs are periodically assessed by requiring the owner or operator of an undervoltage load shedding system to periodically assess and document the effectiveness of its program in coordination with its associated transmission planner and planning authority.

- **PRC-011-0 Undervoltage Load Shedding System Maintenance and Testing (implemented April 1, 2005) —** Ensures that under voltage load shedding equipment is maintained by requiring the owner of an undervoltage load shedding system to develop, document, and implement a maintenance and testing program for its equipment.
- **PRC-012-0 Special Protection System Review Procedure (implemented April 1, 2005) —** Ensures that all special protection systems[15] are properly designed and coordinated with other protections systems, maintained, and tested, and that special protection system misoperations are analyzed and corrected.
- **PRC-013-0 Special Protection System Database (implemented April 1, 2005) —** Ensures that all special protection systems are properly designed, meet performance requirements, and are coordinated with other protection systems by requiring the regional reliability organization to maintain a database of pertinent information about any special protection systems.
- **PRC-014-0 Special Protection System Assessment (implemented April 1, 2005) —** Ensures that special protection systems are properly designed,

[15] A special protection system is a unique system designed to automatically take corrective actions to protect the system under abnormal or predetermined conditions, excluding the coordinated tripping of circuit breakers to isolate faulted components, which is typically the purpose of other protection devices.

meet performance requirements, and are coordinated with other protection systems by requiring the regional reliability organization to assess and document the operation, coordination, compliance with NERC reliability standards, and effectiveness of special protection systems, at least once every five years.

- **PRC-015-0 Special Protection System Data and Documentation (implemented April 1, 2005) —** To ensure that special protection systems are properly designed, meet performance requirements, and are coordinated with other protection systems by requiring the owner of a special protection system to maintain and provide system data and studies in accordance with its regional reliability organization's procedures.
- **PRC-016-0 Special Protection System Misoperations (implemented April 1, 2005) —** Ensures that misoperations of special protection systems are analyzed, and corrective action is taken, by requiring the owner of a such a system to analyze and maintain a record of all misoperations and to take corrective actions to avoid future misoperations.
- **PRC-017-0 Special Protection System Maintenance and Testing (implemented April 1, 2005) —** Ensures that special protection systems are properly maintained by requiring the owner to document and implement a maintenance and testing program that may be reviewed by the regional reliability organization.
- **PRC-020-1 Undervoltage Load Shedding Program Database (effective May 1, 2006, new) —** Ensures that a regional database for undervoltage

load shedding programs is available for bulk power system studies by requiring the regional reliability organization with any entities that have undervoltage load shedding programs to maintain and annually update a database.

  - **PRC-021-1 Undervoltage Load Shedding Program Data (effective August 1, 2006, new) —** Ensures that data is supplied to support the regional undervoltage load shedding database by requiring the owner of such a system to supply data related to its system and other related protection schemes to its regional reliability organization's data base.
  - **PRC-022-1 Under Voltage Load Shedding Program Performance (effective May 1, 2006, new) —** Ensures that undervoltage load shedding programs perform as intended by requiring each entity that operates such a program to analyze and document all of its operations and misoperations and develop a corrective action plan to avoid future misoperations.

- **Transmission Operations (TOP) —** operate transmission facilities within established ratings and the transmission system within operating limits:
  - **TOP-001-0 Reliability Responsibilities and Authorities (implemented April 1, 2005) —** Ensures bulk power system operators have the authority to take actions and direct actions by others, as necessary to maintain bulk power system facilities within limits, thereby protecting transmission, generation, distribution, and customer equipment and preventing cascading failures. Requires that a) transmission operator personnel have the responsibility and authority to direct actions in real-time; b) the

transmission operator, balancing authority, and generator operator follow the directives of their reliability coordinator; and c) that the balancing authority and generator operator follow the directives of the transmission operator. Also requires the transmission operator, balancing authority, generator operator, distribution provider, and load-serving entity to take emergency actions when directed, up to and including shedding load; to keep the transmission system intact; and to communicate actions to others.

- **TOP-002-0 Normal Operations Planning (implemented April 1, 2005)** — Ensures resources and operational plans are in place to enable real-time operators to maintain the bulk power system in a reliable state. Requires transmission operators and balancing authorities to look ahead to the next hour, day, and so on, through the next season, and have operating plans that address these periods. The standard covers a broad array of operating subjects, including procedures to mitigate system operating limit and interconnection reliability operating limit violations[16], confirming real and reactive reserve capabilities, communications, modeling, information exchange, and data confidentiality restrictions.
- **TOP-003-0 Planned Outage Coordination (implemented April 1, 2005)** — Ensures transmission and generation outages are known to others

[16] System operating limits are the values (such as MW, MVar, Amperes, Frequency or Volts) that satisfy the most limiting of the prescribed operating criteria for a specified system configuration to ensure reliable operation. System operating limits are based upon certain operating criteria, including but not limited to: a) pre- and post-contingency equipment or facility ratings; pre- and post-contingency transient and dynamic stability limits; pre- and post-contingency voltage stability); and pre- and post-contingency voltage limits. Interconnection reliability operating limits are the values (such as MW, MVar, amperes, frequency or volts) derived from, or a subset of the system operating limits, which if exceeded, could expose a widespread area of the bulk power system to instability, uncontrolled separation(s) or cascading outages. Transmission operators may not have a sufficiently wide view of the interconnection to be able to recognize when a portion of the interconnection is operating outside an interconnection reliability operating limit.

for the purpose of reliability analysis and decision-making. Requires transmission operators, generator operators, and balancing authorities to coordinate transmission and generator maintenance schedules. The reliability coordinator is authorized to resolve maintenance schedule conflicts.

- **TOP-004-0 Transmission Operations (implemented April 1, 2005) —** Maintains bulk power system facilities within limits, thereby protecting transmission, generation, distribution, and customer equipment and preventing cascading failures. Requires the transmission operator to operate the transmission system within its system operating limits and interconnection reliability operating limits. This standard establishes the "n-1" operating criteria for the transmission system, and requires operating configurations for which limits have not been determined to be treated as emergencies.

- **TOP-005-1 Operational Reliability Information (effective November 1, 2006, replacing TOP-005-0) —** Ensures reliability information is shared among reliability coordinators, transmission operators, and balancing authorities. Requires the transmission operator and balancing authority to provide operating data to each other and to the reliability coordinator, and provides a list of typical operating data that must be provided. The standard also requires reliability coordinators to share information with each other over data applications such as the NERC

Interregional Security Network and execute the NERC Data Confidentiality Agreement for using this network.

- **TOP-006-0 Monitoring System Conditions (implemented April 1, 2005) —** Ensures operating personnel continuously monitor essential bulk power system parameters such as line flows, circuit breaker status, generator resources, relays, weather forecasts, and frequency.
- **TOP-007-0 Reporting SOL and IROL Violations (implemented April 1, 2005) —** Ensures violations of system operating limits and interconnection reliability operating limits are promptly made known to the reliability coordinator, so that the reliability coordinator can direct remedial action and inform other impacted systems. The standard also requires the transmission operator to mitigate an interconnection reliability operating limit violation within 30 minutes, which could require load shedding. Finally, the standard requires the reliability coordinator to take action to mitigate a system operating limit or interconnection reliability operating limit violation if the transmission operator's actions are not effective.
- **TOP-008-0 Response to Transmission Limit Violations (implemented April 1, 2005) —** Ensures violations of system operating limits and interconnection reliability operating limits are promptly corrected by the transmission operator. The standard requires the transmission operator to a) operate so that its actions do not adversely affect other areas of the bulk power system, b) shed load if necessary, c) disconnect equipment that

could be damaged, and d) be able to analyze situations to determine the causes of limit violations.

- **Transmission Planning (TPL) —** design and plan the system to withstand single contingencies, to avoid cascading outages following credible multiple contingencies, and to meet other performance criteria:
    - **TPL-001-0 System Performance Under Normal Conditions (implemented April 1, 2005) —** Ensures that the future bulk power system is planned to meet the system performance requirements by requiring that the transmission planner and the planning authority annually evaluate and document the ability of its transmission system to meet the performance requirements of Table I of TPL-001, with no contingencies, for both the near term and longer-term planning horizons. A documented plan to achieve the performance requirements for the system must be prepared if the system is unable to meet the performance criteria.
    - **TPL-002-0 System Performance Following Loss of a Single BES Element (implemented April 1, 2005) —** Ensures that the future bulk power system is planned to meet the system performance requirements of a system with the loss of one element by requiring that the transmission planner and the planning authority annually evaluate and document the ability of its transmission system to meet the performance requirements of Category B contingencies (loss of a single element) for both the near-term and the long-term planning horizons. A documented plan to achieve the

performance requirements for the system must be prepared if the system is unable to meet the Category B performance criteria.

- **TPL-003-0 System Performance Following Loss of Two or More Bulk Electric System Elements (implemented April 1, 2005) —** Ensures that the future bulk power system is planned to meet the system performance requirements of a system with the loss of multiple elements by requiring that the transmission planner and the planning authority annually evaluate and document the ability of its transmission system to meet the performance requirements of Category C contingencies (loss of two or more elements) for both the near-term and the long-term planning horizons. A documented plan to achieve the performance requirements for the system must be prepared if the system is unable to meet the Category C performance criteria.
- **TPL-004-0 System Performance Following Extreme Bulk Electric System Events (implemented April 1, 2005) —** Ensures that the future bulk power system is evaluated for the risks and consequences to a system for an extreme event with the loss of multiple elements by requiring that the transmission planner and the planning authority annually evaluate and document the risks and consequences of Category D contingencies (extreme event resulting in loss of two or more elements or cascading) for the near-term (five year) planning horizon.
- **TPL-005-0 Regional and Interregional Self-Assessment Reliability Reports (implemented April 1, 2005) —** Ensures that each regional

reliability organization annually conducts reliability assessments of its existing and planned regional bulk power system by requiring the regional reliability organization to assess and document the performance of its power system for both the near-term and long-term planning horizons.

  - **TPL-006-0 Assessment Data from Regional Reliability Organizations (implemented April 1, 2005) —** Ensures that the data necessary to conduct reliability assessments is available by requiring the regional reliability organization to provide NERC with bulk power system data, reports, demand and energy forecasts, and other information necessary to assess reliability and compliance with NERC reliability standards and relevant regional planning criteria.

- **Reactive and Voltage Control (VAR) —** maintain reactive resources and control system voltages to maintain equipment within voltage limits:
  - **VAR-001-0 Voltage and Reactive Control (implemented April 1, 2005)** — Maintains bulk power system facilities within safe voltage limits, thereby protecting transmission, generation, distribution, and customer equipment and avoiding voltage collapse. Requires the transmission operator to monitor and control voltage levels, reactive flows, and reactive resources, to keep these parameters within their reliability limits. This standard also requires the generator operator to provide critical operating data to its transmission operator, and to maintain generator field excitation at proper levels.

- **Glossary of Terms Used in Reliability Standards (most recent update February 7, 2006) —** a glossary of all defined terms used in standards was approved with the Version 0 standards and initially became effective on April 1, 2005. The glossary is updated whenever a new or revised standard is approved that includes new terms or definitions. The glossary may also be approved by a separate standard action using the full procedure (i.e. a change to the glossary can be developed and approved in the same manner as a standard.)

C. Summary of the Development of the Existing NERC Standards

The need to expeditiously translate the existing operating policies and planning standards into reliability standards became apparent in April 2004 as the investigation of the August 2003 northeast blackout drew to a close. The causes of the blackout, including loss of situational awareness by operators, transmission lines sagging into trees, and ineffective communications, could lead to only one conclusion regarding standards, that the existing voluntary operating policies and planning standards would no longer be sufficient for the purpose of monitoring the performance of North American bulk power system owners, operators, and users. As an interim stopgap measure, in April 2004, NERC adopted 40 compliance templates to supplement the highest priority operating policies and planning standards, thereby enabling a more rigorous program of compliance monitoring.

However, that was just a beginning. What was needed was to move quickly to a full set of unambiguous reliability standards. This conclusion was reinforced in the recommendations of the U.S./Canada Power System Outage Task Force report issued on

April 5, 2004.[17] NERC, with the consent and cooperation of its stakeholders, shifted resources from various standards projects under way at the time and launched a concentrated effort to rapidly translate the existing operating policies and planning standards to serve as the starting point for a new body of reliability standards. An important decision at the time, which became even more significant with the passing of reliability legislation in August 2005, was to use the due process provided by the ANSI-accredited procedure to develop and approve these new standards.

These so-called "Version 0" reliability standards were requested in April 2004 and an exceptionally well qualified drafting team of operations and planning experts was formed by early May. The team prepared an initial draft of the standards in 60 days, posting draft 1 on July 9, 2004. Over a 30-day comment period, 87 entities submitted comments to the drafting team. The drafting team prepared responses to each of the comments, and made revisions to the draft standards where appropriate. NERC posted draft 2 and the team's responses to comments from draft 1 for a 45-day period beginning September 1, 2004. The drafting team received an additional 99 sets of comments on draft 2. Once again, the drafting team made changes to the draft standards as appropriate and otherwise responded to each comment. In November 2004, NERC's Operating, Planning, and Market Committees endorsed draft 3 of the standards as a faithful translation of the existing operating policies and planning standards.

NERC posted draft 3 for a 30-day pre-ballot review prior to the commencement of voting on December 7, 2004. In the first round of voting, nine negative votes with comments were received. When one or more negative votes with comments are received,

[17] Recommendation No. 25, U.S.-Canada Power System Outage Task Force Final Report (April 2004), p. 161.

NERC's standards process requires a second, or re-circulation ballot[18]. The re-circulation ballot was conducted from December 27, 2004 through January 7, 2005, providing all ballot pool members with the opportunity to review the 9 negative comments filed during the first ballot and the drafting team's responses to those comments, and to change their vote if they wished.

On the final ballot, stakeholders voted to approve the reliability standards by a weighted-segment average 95.5 percent. This strong affirmation of the standards can be attributed to the commitment of the industry to establish reliability standards and to the drafting team for addressing two major objections that had been raised by stakeholders:

- In lieu of implementing the reliability *authority* function in the standards, the drafting team retained the existing reliability *coordinator* requirements in the Version 0 standards. There was consensus that further work would be required to reconcile the reliability authority function with real-world organization structures before it could be applied in the standards. The reliability coordinator function was well-known to the industry and had been practiced for approximately seven years under requirements established in Operating Policy 9.
- The drafting team removed a portion of the planning standards that had been approved for field testing in September 1997, because those standards required further work to build consensus and the field testing had not been completed. In November 2004, the NERC board directed the completion of these standards in a separate project (call the "Phase III-IV Planning Standards") to follow the

[18] A recirculation ballot, a requirement of ANSI, ensures that even if only one person objects to the standard and offers a reason, the presumption is that reason could be valid and other voters must have an opportunity to hear the objection. The outcome of the second ballot is binding whether or not any objections remain.

Version 0 standards. Part of that work resulted in seven of the new standards that were approved in February 2006 and the remainder of the work is continuing.

Stakeholder comments from the development of the Version 0 standards also identified many opportunities to improve the standards going forward. These comments remain part of the development record and are being forwarded for use by subsequent drafting teams to improve the standards.

The standards were approved on February 7, 2005, and were adopted by the board with an effective date of April 1, 2005. This action brought the total number of standards to 91, one interim cyber security standard previously approved as an urgent action on August 13, 2003, and the 90 new Version 0 standards. The Version 0 standards were implemented into the compliance program on April 1, 2005, and have been in effect since then, except as later revised.

One of the requirements of NERC's standards development procedure is that the formal record of the development of each standard is retained while the standard remains in effect. The formal record of development for the Version 0 reliability standards is provided in Exhibit E. This record includes the approved request to develop the standards, three drafts of the standards, all comments received from stakeholders and the responses to the comments, ballot results, an implementation plan, the drafting team roster, and supporting references mapping the translation of the operating policies and planning standards to reliability standards.

In the development of the Version 0 reliability standards, the drafting team, and NERC as a whole, cooperated with and assisted the North American Reliability Standards Board (NAESB) in developing a complementary set of Version 0 business practice standards. This initial effort focused on areas in which business practices could most readily be separated from reliability requirements in the NERC operating policies. The experience showed the importance of close coordination by NERC and NAESB technical groups. NERC, NAESB, and the ISO/RTO Council (IRC) worked together closely in a spirit of cooperation consistent with the Memorandum of Understanding[19] to resolve issues with the assignment of Version 0 reliability standards and business practices.

Adopting the Version 0 Reliability Standards represented an important milestone for the North American electric power industry by enabling NERC to replace its legacy operating policies, planning standards, and compliance templates with reliability standards. This step addressed the U.S./Canada Power System Outage Task Force final report of April 5, 2004, Recommendation 25, which stated: "NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards."

Although the adoption of the new standards effective April 1, 2005 was principally a translation of the prior rules, several significant improvements were addressed in the translation:

- In the months following the August 2003 northeast blackout, NERC Operating Policies 5, 6, and 9 were substantively revised to remove ambiguities regarding the roles and responsibilities of control areas and reliability coordinators.
- In April 2004, NERC approved 40 new compliance templates adding specific new criteria and measures to supplement the operating policies and planning standards.

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[19] Amended and Restated Memorandum of Understanding for the North American Energy Standards Board, North American Electric Reliability Council and the ISO/RTO Council, effective May 15, 2003.

All of these improvements, affecting approximately half of the standards, were included in the Version 0 standards.

- Requirements were restated in active voice to clarify accountability: "The transmission operator shall …"
- Requirements and measures were rephrased to further clarify intent and remove ambiguities.
- Responsible entities were defined by functional classes (e.g., balancing authorities, transmission operators, generator operators, load-serving entities, etc.) to further sharpen accountability. Assignment of requirements by function is shown in Figure 2 (note that many requirements apply to multiple entities).
- Established a foundation for the continued development and improvement of reliability standards using NERC's open, ANSI-accredited process.

Although the Version 0 Reliability Standards signified an important milestone in NERC's history, it was only a beginning point. An appropriate analogy is that the Version 0 standards represent the establishment of a base camp for standards at 7,000 feet. The revised and new standards recently approved by the board are the first few hundred feet of the climb above the base camp. Much more challenging work is yet to be done to achieve technically excellent reliability standards for the North American bulk power system.

In addition to deferring development of a portion of the planning standards to a later project, two major issues remained at the completion of the Version 0 standards. Because the commitment in the project was to translate the existing operating policies, planning standards, compliance templates, without adding new requirements or compliance measures, 22 of the Version 0 standards did not have measures or other compliance information. These were principally the lower priority operating standards for which no compliance templates had been developed (the planning standards approved in 1997 had compliance elements). A project is currently under way to complete the measures and compliance information for these standards in 2006 so that these standards may become effective on January 1, 2007. It is expected that the revised standards will be filed no later than November 15, 2006.

The second issue is that 23 of the standards required the regional reliability councils to establish regional criteria or procedures. The status of these standards is described in detail in the next two sections.

On February 7, 2006, NERC approved 12 new standards and revisions to ten Version 0 standards.[20] These standards actions are reviewed below.

Standard FAC-003-1 Vegetation Management Program was approved, replacing FAC-003-0. The effective date is April 7, 2006, for reporting requirements and February 7, 2007, for vegetation management program and annual plan requirements, as described in the implementation plan.

An interim standard on vegetation management went into effect on April 1, 2005, with the Version 0 standards. The interim standard required each transmission owner to document its vegetation management program and to report vegetation-related transmission line outages. The new standard provides more a more comprehensive set of requirements for right-of-way vegetation management programs. The new standard

[20] By convention, all new and revised standards after April 1, 2005, are Version "1". Future changes to a Version 1 standard become Version 2, then 3, etc.

applies to 200 kV or higher voltage transmission lines (and lower voltage transmission lines determined to be critical by the regional reliability organizations).

The goal of the new standard is to eliminate nonrandom transmission outages caused by vegetation located in or near the transmission right-of-way. This is achieved by specifying a minimum safe clearance between energized conductors and vegetation, by requiring uniform reporting of vegetation-related transmission outages, and by requiring a vegetation management program to:

- Be documented, with records of implementation.
- Be designed for the geography, vegetation, climate, transmission design configuration, and other factors applicable to the transmission owner's area.
- Specify right-of-way inspection requirements.
- Specify minimum clearances that are no less than the North American minimum clearances.
- Establish requirements for personnel qualifications and training.
- Provide mitigation measures when the transmission owner is prevented from achieving stated clearances.
- Provide an annual maintenance plan and results tracking.

In an initial ballot completed on January 6, 2006, stakeholders provided an affirmative vote in support of the transmission vegetation management standard. Because there were negative votes with comments on the initial ballot, a recirculation ballot was conducted from January 17 to 27. The standard was approved by a weighted average of 88.6 percent, with a quorum of 90.8 percent.

The proposed standard was posted twice for public comment, with adjustments made each time to improve consensus for the standard. At the end, there were several unresolved minority objections to the proposed standard with which the drafting team and the majority of stakeholders disagreed:

- There should not be a zero-tolerance for vegetation-related outages; outages are statistical and achieving zero outages caused by vegetation will not be attainable at a reasonable cost.
- The standard does not distinguish between fall-in contacts, which are random, and sag-in contacts, which are not. A fall-in contact should be viewed as a less severe violation of the standard than a sag-in contact.
- The penalties would be more equitable if they were normalized, for example, based on miles of transmission rather than using an absolute number of outages.
- The standard does not provide leeway for a transmission owner that is blocked from having access to the transmission right-of-way.
- Requiring the transmission owner to have a mitigation plan when the minimum clearances cannot be maintained or verified because access to the right-of-way is blocked sends the wrong message to others. The message is that it is acceptable to block access to the right-of-way and it is up to the transmission owner to devise a mitigation plan.

On February 7, 2006, NERC approved two new standards related to determining facility ratings:

- FAC-008-1: Facility Ratings Methodology (to be effective on May 1, 2006).

- FAC-009-1: Establish and Communicate Facility Ratings (to be effective on July 1, 2006).

Coincident with the effective dates of these new standards, the following Version 0 standards will be retired:

- FAC-004-0: Methodologies for Determining Electrical Facility Ratings
- FAC-005-0: Electrical Facility Ratings for System Modeling

These new standards set the minimum criteria and elements to be considered in the calculation of facility ratings, as necessary to plan and operate the bulk power system. The standards require consideration of manufacturer equipment ratings, system design criteria, ambient conditions, and other applicable assumptions. The standards also set requirements for communicating facility ratings to other reliability entities. The major improvements of the proposed new standards over existing standards include:

- Clarified and more detailed requirements for documenting the calculation of facilities ratings.
- Requirement for communicating such ratings to other affected reliability entities.
- Requirement for peer review of facilities ratings by other affected reliability entities.
- Expanded facility rating requirements to include generators.

These standards were posted four times for stakeholder comment and adjustments made to improve consensus. In the final vote, the proposed facilities ratings standards were approved by a 92.8 percent weighted average across the nine stakeholder segments, with a quorum of 83.9 percent achieved. Some stakeholders objected to the action just prior to balloting to separate these two facilities ratings standards from four other standards addressing system operating limits and transfer capabilities. The drafting team preferred separating the standards into three separate ballots because each set had distinct issues that stakeholders needed to consider when voting.

On February 7, 2006, NERC approved two new standards on determining transfer capabilities, to become effective on the dates indicated:

- FAC-012-1: Transfer Capabilities Methodology (to be effective on May 1, 2006).
- FAC-013-1: Establish and Communicate Transfer Capabilities (to be effective on July 1, 2006).

These standards ensure the methods used by the planning authority and reliability coordinator to determine transfer capability are documented in a procedure and the procedure is communicated to constituents and neighbors. The major improvements of the new standards compared to the existing standards include:

- More detailed requirements for consistent calculation of transfer capabilities.
- Requirements to document the calculation methods and provide the methods to users of the information.
- Additional requirements for the coordination of intra- and interregional transfer capabilities.
- Expanded list of entities responsible for meeting the standards.

The drafting team posted four drafts of these standards for stakeholder input prior to going to ballot. The standards were approved by a weighted average across the stakeholder segments of 90.3 percent, with a quorum of 82.4 percent.

The principal unresolved minority objection at the time of the ballot was that the responsibility for establishing transfer capability calculation methods should reside with the regional reliability organization, not the reliability coordinator.

On February 7, 2006, NERC approved three new reliability standards on coordinate operations to become effective on November 1, 2006:

- IRO-014-1: Procedures to Support Coordination between Reliability Coordinators.
- IRO-015-1: Notifications and Information Exchange between Reliability Coordinators.
- IRO-016-1: Coordination of Real-time Activities between Reliability Coordinators.

Coincident with the effective date of these new reliability standards, the following existing standards will be retired or modified:

- Modify requirement R2; retire requirements R2.1, R2.2, and R2.3 of COM-002-0: Communications and Coordination.
- Modify requirement R2; retire requirement R4 of EOP-002-0: Capacity and Energy Emergencies.
- Retire requirement R2 of IRO-003-0: Reliability Coordination – Wide Area View.
- Retire requirement R6; modify requirement R7 of IRO-004-0: Reliability Coordination – Operations Planning.
- Modify requirements R7, R9, R11, R12, R15 of IRO-005-0: Reliability Coordination – Current Day Operations.
- Retire requirement R3 of TOP-005-0: Operational Reliability Information.

These new standards expand the operating and situational awareness requirements for reliability coordinators, and require the establishment of consistent procedures for the coordination of system conditions, events, and actions among reliability coordinators.

Drafts of the proposed standards were posted four times for stakeholder comments, each time making adjustments to promote consensus. The standards were approved by a 98.4 percent weighted average of the stakeholder segments, with a quorum of 86.5 percent.

Unresolved minority objections were:

- A more precise list of conditions requiring coordination should be defined, as there may be confusion when compliance is measured.
- The standard may leave questions in reviewing a specific violation whether a reliability coordinator had specific knowledge that needed to be coordinated. In other words, there may be conflicts with regard to who knew what first and who was obligated to initiate the coordination.

On February 7, 2006, NERC approved two new standards on the verification of generator capabilities to become effective on the dates noted:

- MOD-024-1 Verification of Generator Gross and Net Real Power Capability (to become effective on April 1, 2006 for regional reliability organization requirements and January 1, 2007 for generator owner requirements, in accordance with the implementation plan).
- MOD-025-1 Verification of Reactive Power Capability (to become effective on January 1, 2007 for regional reliability organizations and on January 1, 2008 for generator owner requirements, in accordance with the implementation plan).

These new standards require regional reliability organizations to develop criteria and procedures for the verification of generator real and reactive power capability, and for generator owners to determine and report those capabilities. The standards provide minimum elements that must be included in the reporting of generator real and reactive capabilities.

Two drafts of the standards were posted for stakeholder comment. The principle issue in reaching consensus was how soon all generators in North America could be compliant with the reactive power capability testing and reporting requirements. Because actual physical testing of each generator is required, completion of the testing must begin no later than 2008 and be completed for 20 percent of all generators per year through 2012.

The standards were approved by a 92 percent weighted average across the stakeholder segments, with a quorum of 76 percent. Unresolved minority views include:

- Concerns with which generator capability parameters need to be measured and reported.
- Preference to measure non-compliance based on percentage of MW generation versus number of generators, which is how the standard defines non-compliance. The issue is how to get an equitable measure of non-compliance when the size and impacts of generators vary substantially and the number of generators to be tested will vary from one for some entities to hundreds for other entities.

On February 7, 2006, NERC approved revisions to three existing standards on transmission and generation protection systems to become effective on the dates indicated:

- PRC-003-1 Regional Requirements for Transmission and Generation Protection System Mis-operations (May 1, 2006)
- PRC-004-1 Analysis and Mitigation of Transmission and Generation Protection System Mis-operations (August 1, 2006)
- PRC-005-1 Transmission and Generation Protection System Maintenance and Testing (May 1, 2006)

Concurrently the following existing standards will be retired:

- PRC-003-0 Regional Procedure for Transmission Protection System Mis-operations (May 1, 2006)
- PRC-004-0 Analysis and Reporting of Transmission Protection System Mis-operations (August 1, 2006)
- PRC-005-0 Transmission Protection System Maintenance and Testing (May 1, 2006)

The revisions provide greater specificity for regional reliability organization procedures for the analysis and reporting of relay mis-operations. The new standards also add requirements for transmission and generator owners to analyze and report relay mis-operations and to have a documented program for relay maintenance and testing.

The draft standards were posted for two comment periods and revised in accordance with stakeholder comments. The standards were approved by a 96 percent weighted average of the stakeholder segments, with a quorum of 76 percent. The principle minority objection was that the implementation timetable was too aggressive.

On February 7, 2006, NERC approved three new standards on under-voltage load shedding programs to become effective on the dates indicated:

- PRC-020-1 Under-Voltage Load Shedding Program Database (May 1, 2006)
- PRC-021-1 Under-Voltage Load Shedding Program Data (August 1, 2006)
- PRC-022-1 Under-Voltage Load Shedding Program Performance (May 1, 2006)

These standards require the regional reliability organizations to maintain a regional database of under-voltage load shedding programs in the region. The standards define the minimum parameters to be recorded in the database and require each entity in the region owning an under-voltage load shedding program to submit the required data into the regional database. Sharing of this data among reliability entities ensures all affected entities will be able to model and analyze the effects of load shedding actions on system performance. The final set of requirements is for the transmission owner to analyze and report any mis-operations of the under-voltage load shedding program.

Drafts of the proposed standards were posted for two comment periods to receive stakeholder inputs. The standards were approved by a weighted average 99 percent of the stakeholder segments, with a 78 percent quorum. An unresolved minority objection is that the standard does not address criteria that would require transmission owners to have an under-voltage load shedding program.

VI. EVALUATION OF EXISTING STANDARDS

This section provides an evaluation of the existing standards compared to the criteria for excellent reliability standards presented in Section III. The evaluation generally addresses the standards as a whole. Individual standards or groups of standards are discussed separately if they have distinguishing characteristics with regard to the evaluation criteria.

Each criterion is briefly summarized (return to Section III for the complete text explaining each criterion), followed by a list of items that must be addressed in 2006, and finally by a list of other areas for improvement.

1. **Applicability —** Each reliability standard shall clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted.

   Each standard that is submitted in Exhibit A lists the entities by functional class to which the standard applies. For example, the following is excerpted from a representative sample standard:

   > **4.** Applicability
   >
   > **1.** 4.1 Transmission Operators.
   >
   > **2.** 4.2 Purchasing-Selling Entities.

   Each standard therefore applies to all bulk power system owners, operators, and users that perform one or more defined functions. The functions are generally based on the NERC reliability functional model and are specifically defined in the Glossary of Terms Used in Reliability Standards.

To further clarify the applicability of the standard, the NERC compliance program registers all bulk power system owners, operators, and users and identifies which functions are performed by each registered entity. To aid entities in understanding which standards apply to them, NERC has developed a matrix of requirements indicating which entities need to meet each requirement. This allows entities to sort the data to identify all the requirements that apply to them.

Areas for improvement: To date there has been no effort to create further specificity in the applicability of the standards. The importance of further specificity can be best explained by use of an example. For instance, a generator operator in literal terms could refer to any entity that operates a power generator synchronized to the grid. This could be large units in excess of 1000 megawatts to a small generator of 1 MW or less. Clearly there is a threshold of size that is relevant to the reliability of the bulk power system, such as 10 or 20 megawatts. There may be other characteristics that necessitate a generator complying with reliability standards.

To ensure that the standards are applied in a cost effective manner and that the reach of the statutory jurisdiction is at an appropriate level relevant to the bulk power system, it is necessary in the future to begin providing greater specificity in the applicability of the standards. This specificity should continue to refer to functional classes of entities, but should seek to further pinpoint the applicable entities by referring to size of the entity, capacity or voltage class of facilities, etc. An example in a new standard under development is that it applies only to transmission owners, operators, and planners that have a commercial nuclear plant interconnected to their system.

The best way to introduce this necessary specificity is to establish a set of guidelines for the standard drafting teams and to require all new standards and revisions going forward to include this degree of specificity.

2. **Purpose —** Each reliability standard shall have a clear statement of the purpose of the standard. The purpose shall describe how the standard contributes to the reliability of the bulk power system.

    Each standard filed has a statement of purpose describing how the standard contributes to bulk power system reliability. The purpose of each standard has been further clarified in Section V of this filing.

    Areas for improvement: There is an opportunity to expand and clarify the reliability purpose of each standard going forward. The filing of the standards with FERC and governmental agencies in Canada serves to elevate the importance of the standards and broadens the audience beyond the industry, for which the previous statements of purpose were targeted. Guidance will be provided to drafting teams going forward to develop greater detail in the purpose statements and expand the intended audience to provide a clear explanation of how the standard contributes to the reliability of the bulk power system.

3. **Performance Requirements —** Each reliability standard shall state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practice and the public interest. Each requirement is not a “lowest common denominator”

compromise, but instead achieves an objective that is the best approach for bulk power system reliability.

The primary elements of each standard are the statements of required performance by the responsible entities. These requirements clearly identify the responsible entity and what action must be performed. This is a substantive improvement that was introduced in the translation of the Version 0 standards from the previous operating policies and planning standards, which were more passively or indirectly stated. A sample performance requirement is:

Each transmission operator shall maintain a list of synchronous generators that are required to follow a voltage or reactive schedule and shall provide each generator operator with its voltage or reactive schedule.

Areas for improvement: There is an opportunity over time with the development of new standards and revisions to the existing standards to continue elevating the specificity and rigor of the performance requirements. NERC expects to annually review standards development goals with the relevant governmental authorities, including how NERC will be sharpening the standards and 'raising the bar' to ensure standards provide a necessary degree of reliability, consistent with good utility practice and the public interest.

4. **Measurability** — Each performance requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

There are 21 standards in Exhibit A for which there are no measures or levels of noncompliance:

CIP-001-0	Sabotage Reporting
COM-001-0	Telecommunications
COM-002-1	Communications and Coordination
EOP-003-0	Load Shedding Plans
EOP-004-0	Disturbance Reporting
EOP-006-0	Reliability Coordination — System Restoration
INT-001-0	Interchange Transaction Tagging
INT-002-0	Interchange Transaction Tag Communication and Assessment
INT-003-0	Interchange Transaction Implementation
IRO-001-0	Reliability Coordination — Responsibilities and Authorities
IRO-002-0	Reliability Coordination — Facilities
IRO-003-1	Reliability Coordination — Wide Area View
IRO-005-1	Reliability Coordination — Current Day Operations
PER-004-0	Reliability Coordination — Staffing
PRC-001-0	System Protection Coordination
TOP-001-0	Reliability Responsibilities and Authorities
TOP-002-0	Normal Operations Planning
TOP-004-0	Transmission Operations
TOP-006-0	Monitoring System Conditions
TOP-008-0	Response to Transmission Limit Violations
VAR-001-0	Voltage and Reactive Control

This status was a direct consequence of translating operating policies and compliance templates into the Version 0 standards. The lower priority operating standards did not have associated compliance templates available. Successfully translating and approving the prior policies and standards dictated that major substantive changes could not be introduced in the process, or else the translation would have been tremendously slowed. These missing measures and levels of noncompliance are being developed through a separate project and will be filed no later than November 8, 2006. The project is described further in Section VI.

Areas for improvement: As a longer term goal, after all standards initially have measures and levels of noncompliance, there are opportunities to further develop and refine the metrics associated with the requirements in the standards. NERC understands the need for additional metrics as a means to strengthen accountability for the standards and in the assessment of penalties for violations.

At the same time, metrics need to be developed carefully and with full opportunity for due process and expert inputs. Poorly designed metrics can weaken reliability performance by shifting the focus away from excellent reliability performance to simply meeting the minimum numeric target. Additionally, operation, planning and design of the bulk power system is an enormously complex enterprise and reliability is best achieved in many areas by not over-prescribing a formula for reliability, but allowing competent and well-trained engineers and operators to make the necessary decisions to keep the system reliable.

There is also an opportunity going forward to shift the metrics in the standards from focusing on procedures and documents to focusing on performance outcomes, consistent with comment made by some in the ERO technical conferences that the standards should focus on the result, not the how. This approach, too, has to be applied with caution. As in other industries critical to the national and public interest, such as commercial airlines, the consequences of failure are sometimes so severe that it is important to not only measure the end result as success or failure, but to also measure the planning, maintenance, and operating practices taken to prevent the failures.

5. **Technical Basis in Engineering and Operations —** Each reliability standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in the particular field.

The standards submitted provide available requirements for reliable operation, planning, and design of bulk power systems and are based on decades of development by expert practitioners from industry.

Areas for improvement: NERC will continue to strive to place the best experts on standard drafting teams. As standards continue to evolve, NERC will seek opportunities for engineering studies, such as was performed by NERC's Planning Committee in developing the proposed new standard on relay loadability (the 'zone 3' issue). A complex new standard requiring significant investment and having significant impacts on the operation and control of the bulk power system deserves deliberate analysis. NERC will continue elevating the technical excellence of its standards by engaging the best experts on drafting teams and by conducting technical studies and field testing of proposed standards.

6. **Completeness —** Reliability standards shall be complete and self-contained. The standards shall not depend on external information to determine the required level of performance.

Certain proposed reliability standards require the regional reliability organizations to develop criteria or procedures for use by entities owning assets or operating within the region. These standards, which have been referred to as the 'fill-in-the-blank' standards, were derived from the previous NERC planning standards. This historical deference to the regional councils to develop regional reliability criteria was based on differing electrical characteristics of the bulk power system; diversity of system and facility designs; state, provincial and local reliability criteria; and accepted utility practice. The NERC standards that fall under this category are listed in Exhibit D.

At issue for the purpose of determining whether NERC standards as filed are enforceable is not whether these standards can be enforced. Very simply — they can be. There is a requirement to provide criteria or a procedure and the criteria and procedures can be inspected and evaluated to determine if they meet the NERC requirements. What is at issue is whether the criteria and procedures adopted by the region can in turn be made enforceable upon bulk power system owners, operators, and users in the region. In essence, information used to determine compliance of these entities is contained in documents outside the NERC standards.

At a minimum the regional criteria and procedures to be enforced should be known to the accountable entities, the ERO and applicable regulatory and governmental authorities. More appropriately, any justifiable regional differences should be approved as an ERO standard, either through the ERO process or an ERO-approved regional standards development process.

Areas for improvement: The solution with the existing standards is not a simple one. To simply withhold the affected standards or not approve them leaves a gap in the bulk power system reliability standards. To enforce the standards, including the application of financial penalties, may not be appropriate if the specific criteria being enforced are not on file with the ERO and the relevant governmental authority. On the other hand, the standards are technically complex and a quick fix is both impractical and dangerous with regard to reliability risks.

In Section VII, NERC proposes a process for developing a detailed work plan and schedule to address the 'fill-in-the-blank' standards. The plan will be filed by November 8, 2006.

7. **Consequences for Noncompliance** — In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, the consequences of violating a standard are clearly known to the responsible entities.

   Two primary inputs in the determination of financial penalties for violation of standards are violation risk factors and levels of noncompliance. The 21 standards with missing levels of noncompliance were previously described and the plan to complete those for filing by November 8, 2006 is provided in Section VII. Similarly, a plan for the development and approval of the risk factors associated with each requirement is provided in Section VII. NERC will file the approved risk factors for all requirements by November 8, 2006.

   Areas for improvement: As the compliance program is implemented with financial penalties, the risk factors, levels of noncompliance and other compliance guidelines will be periodically evaluated to determine opportunities for improvement.

8. **Clear Language** — Each reliability standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in

keeping with good utility practice, are able to arrive at a consistent interpretation of the required performance.

The Version 0 translation provided substantive improvement in this area. Requirements were stated in an active voice with clear reference to the responsible party. When possible, words like “adequate” were replaced with more specific language.

Areas for improvement: The biggest opportunity in this area is to improve the measurability of the performance requirements. Despite the best effort for improvement in the Version 0 translation, the drafting team was restrained from making substantive improvements that would change the meaning of the standards. Therefore, there remain instances in which words such as “adequate” remain within a requirement — given other priorities, there has not yet been an opportunity to develop those more specific criteria. These improvements are best handled through the regular review and updates of the standards.

9. **Practicality —** Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

All issues concerning practicality of a standard are addressed by the extensive opportunities for stakeholder review and comment on all standards. Stakeholders also have an opportunity to vote on all standards and may choose to vote no if a standard is impractical. Some standards that introduce new methods or measures are field tested to demonstrate practicality. There are currently two field tests in progress for proposed new standards on balancing resources and demand, organization certification, and general reactive power capability verification.

Areas for improvement: Issues of practicality of standards will continue to be addressed through stakeholder input and comment on standards.

10. **Consistent Terminology —** To the extent possible, reliability standards shall use a set of standard terms and definitions that are approved through the NERC reliability standards development process.

    The Glossary of Terms Used in Reliability Standards defines all defined terms in the standards. The glossary was an amalgamation of several previous NERC glossaries. The glossary was approved in the Version 0 translation, has the same status as the reliability standards, and is subject to relevant governmental approval. A degree of caution was applied in creating this initial glossary by not including every possible term. Where it was thought that the English language interpretation would be sufficiently clear in the context of the standard, such as the word 'dynamic', those definitions were omitted.

    Areas for improvement: NERC will continue to develop and expand the glossary of terms used in the standards and strive to ensure consistency between technical terms and those used in statutes and regulations in Canada.

In conclusion, the existing NERC standards provide a solid foundation for beginning the ERO and represent decades of experience and expertise in the design, planning, operation, maintenance, and uses of the bulk power system. Holding bulk power system owners, operators, and users accountable for meeting these standards provides an acceptable threshold of reliability while new standards are being developed and the existing standards are improved.

B. Regional Reliability Standards

One issue that does not arise with this filing, but will be a consideration in the future is the approval of regional reliability standards. The current set of proposed standards in Exhibit A does not contain any regional reliability standards. There are seven variances included within the NERC standards, but each is a part of the NERC standard itself and there is not a separate regional standard. As noted in Section V, the seven existing variances within the existing standards are:

Standard	Regional Difference	Region/RTO	Type
BAL-001-0	Control Performance Standard 2	ERCOT	Technical — standard is not applicable to a single balancing authority interconnection.
INT-001-0 INT-004-0	Tagging Dynamic Schedules and Inadvertent Payback	WECC	Agreed upon interconnection-wide scheduling practice.
BAL-006-0	RTO Inadvertent Interchange Accounting	MISO	Addresses RTO containing multiple balancing authorities.
INT-002-0 INT-003-0	Scheduling Agent	MISO/SPP	Allows RTO market practice.
INT-002-0 INT-003-0	Enhanced Scheduling Agent	MISO	Allows RTO market practice.
INT-001-0 INT-003-0	Energy Flow Information	MISO	Allows RTO market practice.
IRO-006-0	Enhanced Congestion Management (Curtailment/ Reload/Reallocation)	PJM/MISO	Allows RTO market practice.

ERO rules of procedure 311 to 314 define the procedure NERC will use to review proposed regional reliability standards that would be considered for filing with applicable governmental agencies. NERC will publicly notice and request comment on a proposed regional reliability standard, allowing a minimum of 45 days for comments. The regional entity would have an opportunity to resolve any objections identified in the comments and may choose to withdraw the request, revise the proposed standard and request another posting for comment or submit the proposed standard along with its consideration of any comments received, for approval by NERC.

VII. WORK PLAN FOR IMPROVING RELIABILITY STANDARDS

This section describes a 2006 work plan to ensure the reliability standards presented in Exhibit A, and additional standards to be filed during 2006, are ready to become effective on January 1, 2007. The plan addresses three areas of work: a) modifications to the standards necessary to make them ready for implementation by the ERO; b) modifications to NERC procedures that must be approved and in place prior to operation as the ERO; and c) additional standards NERC plans to file with FERC and governmental authorities in Canada. NERC plans to file all supplemental information described in this section as soon as possible but no later than November 8, 2006.

A. Actions to Prepare Standards for Approval

The first project is to complete the compliance elements in the 21 standards currently missing compliance elements. A request for this project was submitted to NERC in March 2005 after the adoption of the Version 0 standards. Based on stakeholder consensus on the scope of work and justification, in August 2005 the Standards Committee authorized the development of measures and compliance elements for the 21 standards. With the passing of U.S. legislation, the timetable for completing the missing compliance elements was accelerated from a phased effort over several years to one that will be completed in 2006.

The drafting team developed and posted a pilot standard for comment through March 20, 2006. Based on comments received from that posting, the drafting team has prepared draft measures and compliance elements for the remaining the 20 standards. All 21 of the standards will be posted for a 45-day comment period beginning April 15, 2006. A second posting for comment is expected on July 1. The revised standards will be posted for pre-ballot review beginning September 1, with balloting conducted in October. The standards will be submitted for NERC board approval on November 1 and filed no later than November 8, 2006. The new measures and compliance elements are expected to be ready for implementation in the compliance program beginning January 1, 2007.

Going forward, NERC plans to retain the measures associated with each requirement in the standards. However, the levels of noncompliance, which are used by the compliance program in determining financial penalties, will be removed from the standards and developed through a separate process within the compliance program. The reason for this change is that the technically oriented drafting teams developing the standards typically do not have sufficient expertise in compliance monitoring procedures. Better results are achieved when the drafting team focuses on the technical content of the standard, namely the requirements and measures. The compliance program expects to have such a procedure defined for NERC board approval in August 2006. The existing standards balloting procedure will be used to approve levels of noncompliance until such a procedure is available.

A second project to be completed before the implementation of financial penalties is the addition of the risk factors to all standards included in Exhibit A, as well as all new standards planned for filing by November 8, 2006. NERC has already preliminarily ranked each requirement in all existing and emerging standards with regard to the reliability risk of violating each requirement. A high risk requirement is one in which a violation could cause or increase the severity of a cascading failure of the grid. A medium risk requirement could affect the state of the electric system, the capability of the system to operate reliably, or situational awareness. Lower risk requirements are administrative in nature, such as reporting requirements. These risk factors are a primary element in NERC's proposed Guidelines for Penalties and Sanctions.

NERC's Standards Committee and Compliance and Certification Committee jointly developed a white paper proposing the use of risk factors in October 2005. A request to develop the risk factors, including definitions of the risk levels, was posted for comment on January 17, 2006. The drafting team has proposed a preliminary set of risk factors associated with the requirements in the existing standards. The risk factors will be subject to stakeholder review and input through two public postings, the first beginning April 15 and the second beginning July 1. During each posting, the industry will be asked to rank each of the requirements in the existing standards as high, medium, or lower risk. The drafting team will consider the results of these surveys in refining its recommended risk factors. The drafting team will also develop risk factors for standards that will be balloted during 2006 for filing by November 8. Risk factors for later standards will be assigned to the regular drafting teams as they work on the standards.

NERC plans to conduct a ballot of the risk factors in October 2006, following a 30-day pre-ballot review beginning September 1. The risk factors will be presented to the NERC board on November 1 for approval and will be filed no later than November 8 for approval. The risk factors will be balloted using a single ballot. The existing content of the standards will not be subject to review or approval, only the addition of the risk factor for each requirement.

Once the missing compliance elements and the risk factors are approved as described above, NERC will modify the format of its existing standards to add the assigned risk factor to each requirement in the standards. This step will establish a format going forward in which the risk factor is developed within the standard. The format will also show the levels of noncompliance removed from the standards and posted as separate compliance information.

The third major effort to prepare the standards for implementation is to complete an evaluation of the 'fill-in-the-blank' regional standards and present a plan for addressing these standards.

First, where the authority exists, NERC is requesting approval of the first group of standards: EOP-007, IRO-001, MOD-003, MOD-011, MOD-013, MOD-014, MOD-015, MOD-016, PRC-002, PRC-003, PRC-006, PRC-012, PRC-013, and PRC-014. These standards only impose NERC requirements on regional reliability organizations and do not obligate entities within the region.

For the remaining 25 standards[21] that do contain requirements for entities within a regional to comply with regional reliability organization criteria or procedures, there are several possible approaches. NERC is recommending conditional approval of these 25 standards to become effective as ERO reliability standards on January 1, 2007. NERC is recommending that the ERO and the regional entities will enforce compliance with these standards, except that there shall be no determination of a violation of a reliability standard based on a failure to comply with regional criteria or procedures that are not part of an approved reliability standard.

NERC will complete the following activities by November 8, 2006. First, NERC will hire a full-time regional standards manager to coordinate the review and development of regional standards. This person will ensure the regional standards have a

[21] BAL-002, EOP-004, EOP-009, FAC-001, FAC-002, FAC-004, MOD-001, MOD-002, MOD-004, MOD-005, MOD-008, MOD-009, MOD-010, MOD-012, MOD-017, MOD-019, MOD-024, MOD-025, PER-002, PRC-004, PRC-007, PRC-008, PRC-009, PRC-015, and PRC-016

high degree of consistency. By May 31, 2006, NERC will collect the regional criteria, procedures, and other documents that the existing standards require regional reliability organizations to have in place.

NERC will form a task group consisting of the NERC regional standards manager and a representative from each regional reliability organization with expertise in the regional criteria. The task group will review the status and consistency of the regional criteria and procedures, and determine a recommended course of action for each standard.

The task group will prepare a detailed report and work plan for NERC board approval on November 1, and file the report and work plan with governmental authorities on November 8, 2006. The plan will provide a detailed schedule for addressing all of the conditionally approved regional fill-in-the-blank standards by either a) developing uniform North American standards to replace the regional standards; b) developing regional reliability standards through approved procedures; or c) not including the regional criteria within reliability standards.

B. Process Changes in 2006 in Preparation for ERO Implementation

In addition to the activities described above to prepare the existing standards to become effective January 1, 2007, NERC will be modifying its Reliability Standards Development Procedure to be consistent with NERC's role as the ERO. The modifications have been drafted and will be posted for stakeholder comment through May 15. A pre-ballot review will be conducted in June and the procedure will be subject to a ballot of the stakeholders in July 2006. The modified procedure will be submitted for board approval on August 2, 2006. If there are substantive unresolved stakeholder comments from the first posting, an alternative schedule will be to make additional changes to the procedure and post it for a second comment period from June 1 through July 15. In this case, a pre-ballot posting would begin August 1 and the procedure would be balloted in September, with board approval by September 30.

The major substantive changes from the existing procedure are to:

- Add the risk factors to the standard template and define the risk factors.
- Remove the levels of non-compliance from the standard template.
- Revise the balloting procedure to allow partial weighting of a segment that has less than 10 voters for a standard action. This step will limit the weight of any single vote to 1.11% of the total vote.
- Modify the criteria for Segment 8, Small End Use Customer, to ensure the segment is comprised of only small end users and their advocates and does not included persons that have material interests affiliated with other segments, such as employees, consultants, or vendors of any entity that is qualified to join any other segment.

C. Additional Reliability Standards to be Filed in 2006

During 2006, while preparing to become the ERO, NERC is continuing to develop reliability standards. Several of these new standards are associated with 2003 blackout recommendations or are critical aspects of bulk power system reliability. NERC proposes to file these standards with governmental authorities during 2006, immediately after NERC board approval. The following standards are scheduled for filing no later than November 8:

- Cyber security standards — In response to the September 11, 2001 terrorist attacks on the United States, NERC adopted its cyber security guidelines as an urgent action standard. This interim standard is set to expire in August 2006. The new permanent standards will set requirements for the identification of critical cyber security assets and the protection of those assets. The standards set requirements for security management programs, electronic and physical protection, personnel, incident reporting, and recovery plans. The eight new standards have been approved by ballot of the stakeholders and will be presented to the NERC board for adoption on May 2, 2006. NERC expects to file these new standards with governmental authorities by May 12, with a requested effective date of January 1, 2007.

- Relay loadability — NERC is developing a new standard in response to the cascading transmission outages that occurred in the August 2003 blackout when backup distance and phase relays operated on high loading and low voltage without electrical faults on the protected lines. This so-called 'zone 3 relay' issue has been expanded to address other protection devices subject to unintended operation during extreme system conditions. The standard will establish minimum loadability criteria for these relays to minimize the chance of unnecessary line trips during a major system disturbance. In December 2005, the NERC Planning Committee approved a white paper providing the engineering basis for the proposed standard, culminating a major project to analyze the performance of existing protection systems and to research preferred set points. The new standard is scheduled for balloting in October 2006 and board approval on November 1, 2006. The standard will be filed with governmental authorities on November 8, 2006. The proposed effective date has not yet been determined.

- Additional Phase III-IV planning standards — Work is continuing on the remaining planning standards not included in Version 0. These standards address disturbance monitoring and reporting; reactive power and voltage control; verification of generator capabilities; system modeling; system protection and control; system restoration; and black-start capability. These standards will be scheduled for board approval and filing with governmental authorities as they are approved by stakeholder ballot during 2006.
- Nuclear plant offsite power supply — This proposed standard addresses the requirements for grid planning and operations to incorporate nuclear power plant licensing requirements for off site power necessary for safe plant shutdown. The standard is on schedule for adoption in late 2006.
- Coordinate interchange — These proposed standards expand and clarify the reliability requirements for power transactions. The standards have been approved by stakeholder ballot and are ready for board adoption on May 2, 2006, and filing with governmental authorities by May 12, 2006.
- Personnel training — This proposed standard will establish new requirements for the development, implementation, and maintenance of system personnel training programs. A draft of the standard will be completed in 2006, with balloting scheduled for the 1st quarter of 2007. The standard will promote quality training programs for the initial and continuing education of real-time operating personnel as well as other personnel supporting the reliable operation of bulk electric systems.
- Organization certification standards for transmission operators, balancing authorities, and reliability coordinators — These proposed standards establish minimum

qualifications for the three functions with primary responsibility for reliable operation of the bulk electric system. Criteria include authorities, facilities and tools, communications, personnel, procedures, emergency plans, etc. The standards will be used to certify organizations as capable of performing these functions. The standards are currently in field testing and will be revised based on what is learned in the field tests. Balloting is expected in 2006.

In concert with developing the 2007 business plan and budget for standards development, NERC will communicate with federal, state, and provincial government agencies in the United States and Canada regarding the standards work plan and results. NERC will propose an informal conference of a consultative nature to fully understand the needs of governmental authorities in the U.S. and Canada for reliability standards. This informal conference is proposed for completion in the fall of 2006 before the 2007 budget is approved. The goal will be to prioritize the use of resources in improving the standards.

In summary the deliverables from the NERC standards program in 2006 to enable implementation of the ERO on January 1, 2007 are as follows:

- 21 standards modified to add missing measures and compliance information.
- A table of reliability risk factors for each requirement in all existing and new reliability standards filed up through November 8, 2006.
- Updated set of reliability standards in the new format to include risk factors and removal of levels of noncompliance.
- Work plan and schedule for addressing regional 'fill-in-the-blank' standards.
- Updated Reliability Standards Development Procedure.

- New standards addressing cyber security, relay loadability, additional Phase III-IV planning requirements, coordinating interchange, and nuclear plant offsite power supply reliability.

C. Longer Term Improvements to be Addressed in Future Year Work Plans

There are a number of general improvements to be made to the standards beyond 2006:

- The applicability section of each standard, which states the entities to which the standard applies, must be expanded substantially to identify all exemptions from the standard, including based on equipment characteristics, such as all generators smaller than a certain size.
- Additional metrics must be added to standards in areas that are suited for quantitative measurement.
- The NERC reliability standards process requires each standard to be reviewed at least once every five years. This periodic review ensures that even the least significant standards will receive appropriate scrutiny and necessary improvements over time.

VIII. CONCLUSION

NERC looks forward to working with the Ministry of Energy to make its reliability standards mandatory and enforceable in New Brunswick. NERC requests the Ministry's views on the work plan provided in Section VII.

NERC requests the Ministry to provide feedback on the benchmarks for an excellent reliability standard, so that such benchmarks can be used to guide for the future development of reliability standards and the evaluation of standards that are filed with the Ministry.

NERC requests the Ministry to provide feedback on adequacy of the information provided with this filing of standards, and guidance on the appropriate information to be provided for future filings.

Respectfully submitted,

NORTH AMERICAN ELECTRIC
RELIABILITY COUNCIL

By ___/s/ Rick Sergel_____
President and Chief Executive Officer
North American Electric Reliability Council
116-390 Village Boulevard
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April 4, 2006

Exhibit A — Reliability Standards

Reliability Standards for the Bulk Electric Systems of North America

February 7, 2006

North American Electric Reliability Council

North American Electric Reliability Council

Reliability Standards Approved

BAL	Resource and Demand Balancing	**MOD**	Modeling, Data, and Analysis
CIP	Critical Infrastructure Protection	**ORG**	Organization Certification
COM	Communications	**PER**	Personnel Performance, Training, and Qualifications
EOP	Emergency Preparedness and Operations	**PRC**	Protection and Control
FAC	Facilities Design, Connections and Maintenance	**TOP**	Transmission Operations
INT	Interchange Scheduling and Coordination	**TPL**	Transmission Planning
IRO	Interconnection Reliability Operations and Coordination	**VAR**	Voltage and Reactive

Standard Number	Title	Effective Date
Resource and Demand Balancing		
BAL-001-0	Real Power Balancing Control Performance	04/01/05
BAL-002-0	Disturbance Control Performance	04/01/05
BAL-003-0	Frequency Response and Bias	04/01/05
BAL-004-0	Time Error Correction	04/01/05
BAL-005-0	Automatic Generation Control	04/01/05
BAL-006-0	Inadvertent Interchange	04/01/05
Critical Infrastructure Protection		
1200	Urgent Action Standard - Cyber Security	08/13/03
CIP-001-0	Sabotage Reporting	04/01/05
Communications		
COM-001-0	Telecommunications	04/01/05
COM-002-1	Communications and Coordination	11/01/06
Emergency Preparedness and Operations		
EOP-001-0	Emergency Operations Planning	04/01/05
EOP-002-1	Capacity and Energy Emergencies	11/01/06
EOP-003-0	Load Shedding Plans	04/01/05
EOP-004-0	Disturbance Reporting	04/01/05
EOP-005-0	System Restoration Plans	04/01/05
EOP-006-0	Reliability Coordination - System Restoration	04/01/05
EOP-007-0	Establish, Maintain, and Document a Regional Blackstart Capability Plan	04/01/05
EOP-008-0	Plans for Loss of Control Center Functionality	04/01/05
EOP-009-0	Documentation of Blackstart Generating Unit Test Results	04/01/05
Facilities Design, Connections and Maintenanct		
FAC-001-0	Facility Connection Requirements	04/01/05

Standard Number	Title	Effective Date
FAC-002-0	Coordination of Plans for New Facilities	04/01/05
FAC-003-1	Vegetation Management Program	04/07/06
FAC-004-0	Methodologies for Determining Electrical Facility Ratings	04/01/05
FAC-005-0	Electrical Facility Ratings for System Modeling	04/01/05
FAC-008-1	Facility Ratings Methodology	08/07/06
FAC-009-1	Establish and Communicate Facility Ratings	10/07/06
FAC-012-1	Transfer Capabilities Methodology	08/07/06
FAC-013-1	Establish and Communicate Transfer Capabilities	10/07/06
Interchange Scheduling and Coordination		
INT-001-0	Interchange Transaction Tagging	04/01/05
INT-002-0	Interchange Transaction Tag Communication and Assessment	04/01/05
INT-003-0	Interchange Transaction Implementation	04/01/05
INT-004-0	Interchange Transaction Modifications	04/01/05
Interconnection Reliability Operations and Coordination		
IRO-001-0	Reliability Coordination – Responsibilities and Authorities	04/01/05
IRO-002-0	Reliability Coordination – Facilities	04/01/05
IRO-003-1	Reliability Coordination – Wide Area View	08/01/06
IRO-004-1	Reliability Coordination - Operations Planning	11/01/06
IRO-005-1	Reliability Coordination – Current Day Operations	11/01/06
IRO-006-1	Reliability Coordination – Transmission Loading Relief	08/08/05
IRO-014-1	Procedures to Support Coordination Between Reliability Coordinators	11/01/06
IRO-015-1	Notifications and Information Exchange Between Reliability Coordinators	11/01/06
IRO-016-1	Coordination of Real-time Activities Between Reliability Coordinators	11/01/06
Modeling, Data, and Analysis		
MOD-001-0	Documentation of TTC and ATC Calculation Methodologies	04/01/05
MOD-002-0	Review of TTC and ATC Calculations and Results	04/01/05
MOD-003-0	Procedure for Input on TTC and ATC Methodologies and Values	04/01/05
MOD-004-0	Documentation of Regional CBM Methodologies	04/01/05
MOD-005-0	Procedure for Verifying CBM Values	04/01/05
MOD-006-0	Procedures for Use of CBM Values	04/01/05
MOD-007-0	Documentation of the Use of CBM	04/01/05
MOD-008-0	Documentation and Content of Each Regional TRM Methodology	04/01/05
MOD-009-0	Procedure for Verifying TRM Values	04/01/05
MOD-010-0	Steady-State Data for Transmission System Modeling and Simulation	04/01/05

Standard Number	Title	Effective Date
MOD-011-0	Regional Steady-State Data Requirements and Reporting Procedures	04/01/05
MOD-012-0	Dynamics Data for Transmission System Modeling and Simulation	04/01/05
MOD-013-0	RRO Dynamics Data Requirements and Reporting Procedures	04/01/05
MOD-014-0	Development of Interconnection-Specific Steady State System Models	04/01/05
MOD-015-0	Development of Interconnection-Specific Dynamics System Models	04/01/05
MOD-016-0	Actual and Forecast Demands, Net Energy for Load, Controllable DSM	04/01/05
MOD-017-0	Aggregated Actual and Forecast Demands and Net Energy for Load	04/01/05
MOD-018-0	Reports of Actual and Forecast Demand Data	04/01/05
MOD-019-0	Forecasts of Interruptible Demands and DCLM Data	04/01/05
MOD-020-0	Providing Interruptible Demands and DCLM Data	04/01/05
MOD-021-0	Accounting Methodology for Effects of Controllable DSM in Forecasts	04/01/05
MOD-024-1	Verification of Generator Gross and Net Real Power Capability	04/01/06
MOD-025-1	Verification of Reactive Power Capability	01/01/07
Organization Certification		
	None at this time.	
Personnel Performance, Training, and Qualifications		
PER-001-0	Operating Personnel Responsibility and Authority	04/01/05
PER-002-0	Operating Personnel Training	04/01/05
PER-003-0	Operating Personnel Credentials	04/01/05
PER-004-0	Reliability Coordination – Staffing	04/01/05
Protection and Control		
PRC-001-0	System Protection Coordination	04/01/05
PRC-002-0	Define and Document Disturbance Monitoring Equipment Requirements	04/01/05
PRC-003-1	Regional Requirements for Transmission and Generation Protection System Misoperations	05/01/06
PRC-004-1	Analysis and Mitigation of Transmission and Generation Protection System Misoperations	08/01/06
PRC-005-1	Transmission and Generation Protection System Maintenance and Testing	05/01/06
PRC-006-0	Development and Documentation of Regional UFLS Programs	04/01/05
PRC-007-0	Assuring Consistency with Regional UFLS Programs	04/01/05
PRC-008-0	Underfrequency Load Shedding Equipment Maintenance Programs	04/01/05
PRC-009-0	UFLS Performance Following an Underfrequency Event	04/01/05
PRC-010-0	Assessment of the Design and Effectiveness of UVLS Program	04/01/05
PRC-011-0	UVLS System Maintenance and Testing	04/01/05

Standard Number	Title	Effective Date
PRC-012-0	Special Protection System Review Procedure	04/01/05
PRC-013-0	Special Protection System Database	04/01/05
PRC-014-0	Special Protection System Assessment	04/01/05
PRC-015-0	Special Protection System Data and Documentation	04/01/05
PRC-016-0	Special Protection System Misoperations	04/01/05
PRC-017-0	Special Protection System Maintenance and Testing	04/01/05
PRC-020-1	Under-Voltage Load Shedding Program Database	05/01/06
PRC-021-1	Under-Voltage Load Shedding Program Data	08/01/06
PRC-022-1	Under-Voltage Load Shedding Program Performance	05/01/06
Transmission Operations		
TOP-001-0	Reliability Responsibilities and Authorities	04/01/05
TOP-002-0	Normal Operations Planning	04/01/05
TOP-003-0	Planned Outage Coordination	04/01/05
TOP-004-0	Transmission Operations	04/01/05
TOP-005-1	Operational Reliability Information	11/01/06
TOP-006-0	Monitoring System Conditions	04/01/05
TOP-007-0	Reporting SOL and IROL Violations	04/01/05
TOP-008-0	Response to Transmission Limit Violations	04/01/05
Transmission Planning		
TPL-001-0	System Performance Under Normal Conditions	04/01/05
TPL-002-0	System Performance Following Loss of a Single BES Element	04/01/05
TPL-003-0	System Performance Following Loss of Two or More BES Elements	04/01/05
TPL-004-0	System Performance Following Extreme BES Events	04/01/05
TPL-005-0	Regional and Interregional Self-Assessment Reliability Reports	04/01/05
TPL-006-0	Assessment Data from Regional Reliability Organizations	04/01/05
Voltage and Reactive		
VAR-001-0	Voltage and Reactive Control	04/01/05

A. Introduction

1. **Title**: **Real Power Balancing Control Performance**
2. **Number**: BAL-001-0
3. **Purpose**: To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.
4. **Applicability**:
   4.1. Balancing Authorities
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \epsilon_1^2 \text{ or } \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\epsilon_1^2} \le 1$$

The equation for ACE is:

ACE = $(NI_A - NI_S) - 10B(F_A - F_S) - I_{ME}$

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

$$AVG_{10-\text{minute}}(ACE_i) \le L_{10}$$

where:

$$L_{10} = 1.65 \in_{10} \sqrt{(-10B_i)(-10B_s)}$$

ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.

R3. Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.

R4. Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).

C. Measures

M1. Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

CPS1 = (2 - CF) * 100%

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12-\text{month}}}{(\in_1)^2}$$

where: ε_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\dfrac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{-10\text{B}}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error will be used to compute the respective hourly average compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$\text{CF}_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(\text{CF}_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month compliance factor becomes:

$$\text{CF}_{\text{12-month}} = \frac{\sum_{i=1}^{12} (CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-i})]}{\sum_{i=1}^{12} [n_{(\text{one-minute samples in month})-i}]}$$

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

M2. Each Balancing Authority shall achieve, as a minimum, Requirement R2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}})} \right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L_{10}. ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

Violation clock-ten-minutes

$$= 0 \text{ if } \left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| \le L_{10}$$

$$= 1 \text{ if } \left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| > L_{10}$$

Each Balancing Authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 requires that ACE be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.

A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of ACE.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month.

1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Attachment 1-BAL-001-0) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each Balancing Authority shall retain for a rolling 12-month period the values of: one-minute average ACE (ACE_i), one-minute average Frequency Error, and, if using variable bias, one-minute average Frequency Bias.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance – CPS1

2.1. Level 1: The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.

2.2. Level 2: The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.

2.3. Level 3: The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.

2.4. Level 4: The Balancing Authority Area's value of CPS1 is less than 85%.

3. Levels of Non-Compliance – CPS2

3.1. Level 1: The Balancing Authority Area's value of CPS2 is less than 90% but greater than or equal to 85%.

3.2. Level 2: The Balancing Authority Area's value of CPS2 is less than 85% but greater than or equal to 80%.

3.3. Level 3: The Balancing Authority Area's value of CPS2 is less than 80% but greater than or equal to 75%.

3.4. Level 4: The Balancing Authority Area's value of CPS2 is less than 75%.

E. Regional Differences

1. The ERCOT Control Performance Standard 2 Waiver approved November 21, 2002.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

Attachment 1-BAL-001-0
CPS1 and CPS2 Data

CPS1 DATA	Description	Retention Requirements
ε_1	A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.	Retain the value of ε_1 used in CPS1 calculation.
ACE_i	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (525,600 values).
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value(s) of B_i used in the CPS1 calculation.
F_A	The actual measured frequency.	Retain the 1-minute average frequency values (525,600 values).
F_S	Scheduled frequency for the Interconnection.	Retain the 1-minute average frequency values (525,600 values).

CPS2 DATA	Description	Retention Requirements
V	Number of incidents per hour in which the absolute value of ACE clock-ten-minutes is greater than L_{10}.	Retain the values of V used in CPS2 calculation.
ε_{10}	A constant derived from the frequency bound. It is the same for each Balancing Authority Area within an Interconnection.	Retain the value of ε_{10} used in CPS2 calculation.
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value of B_i used in the CPS2 calculation.
B_s	The sum of Frequency Bias of the Balancing Authority Areas in the respective Interconnection. For systems with variable bias, this is equal to the sum of the minimum Frequency Bias Setting.	Retain the value of B_s used in the CPS2 calculation. Retain the 1-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS2.	Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.

Introduction

1. **Title:** **Disturbance Control Performance**

2. **Number:** BAL-002-0

3. **Purpose:**

   The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)

   4.3. Regional Reliability Organizations

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group.

R2.2. Its allocation among members.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.

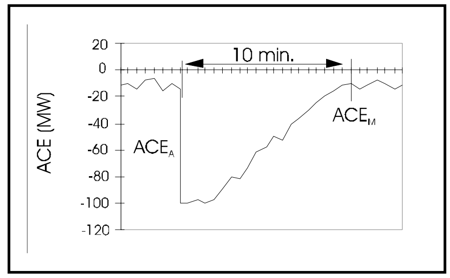
R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

R6.2. The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the NERC Operating Committee.

C. Measures

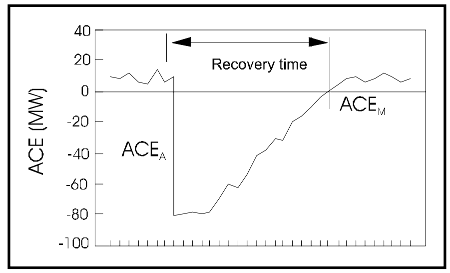
M1. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_i).

For loss of generation:



if $ACE_A < 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$



if $ACE_A \geq 0$
then

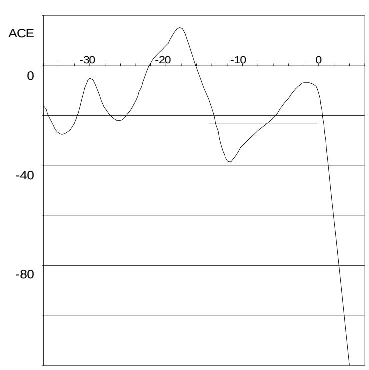
$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

where:

- MW_{LOSS} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15\ min}$, and
- ACE_m is the minimum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or reserve sharing group may, at their discretion, set $ACE_m = ACE_{15\ min}$.

The Balancing Authority or Reserve Sharing Group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of ACE_A = - 25 MW.



The average percent recovery is the arithmetic average of all the calculated R_i's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "NERC Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Reliability Organization must submit a summary document reporting compliance with DCS to NERC no later than the 20^{th} day of the month following the end of the quarter.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

1.4. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. Levels of Non-Compliance

Each Balancing Authority or Reserve Sharing Group not meeting the DCS during a given calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter (offset by one month) following the evaluation by the NERC or Compliance Monitor [e.g. for the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the DCS in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the most severe single Contingency. A Reserve Sharing Group may choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing Group provided that this increase is fully allocated.

A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing Group will apply the appropriate DCS performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.

2.1. **Level 1:** Value of the average percent recovery for the quarter is less than 100% but greater than or equal to 95%.

2.2. **Level 2:** Value of the average percent recovery for the quarter is less than 95% but greater than or equal to 90%.

2.3. **Level 3:** Value of average percent recovery for the quarter is less than 90% but greater than or equal to 85%.

2.4. **Level 4:** Value of average percent recovery for the quarter is less than 85%.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

A. Introduction

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

2. **Number:** BAL-003-0

3. **Purpose:**

   This standard provides a consistent method for calculating the Frequency Bias component of ACE.

4. **Applicability:**

   4.1. Balancing Authorities

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.

R1.1. The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.

R1.2. Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.

R2. Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:

R2.1. The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation. The Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours.

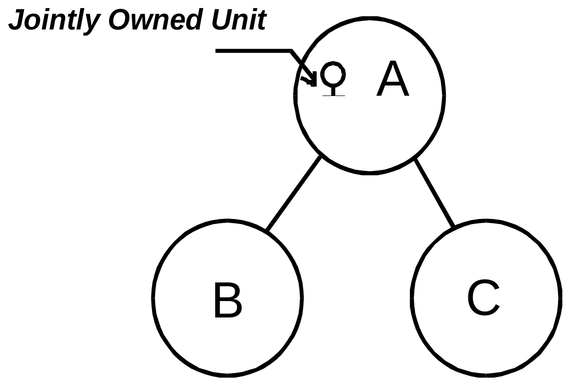
R2.2. The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.

R3. Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

R4. Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.

R4.1. Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C). See the diagram below.

R4.2. The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting.



R5. Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.

R5.1. Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.

R6. A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.

C. Measures

M1. Each Balancing Authority shall perform Frequency Response surveys when called for by the Operating Committee to determine the Balancing Authority's response to Interconnection Frequency Deviations.

D. Compliance

Not Specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

A. Introduction

1. **Title:** **Time Error Correction**

2. **Number:** BAL-004-0

3. **Purpose:**

   The purpose of this standard is to ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection.

4. **Applicability:**

   4.1. Reliability Coordinators

   4.2. Balancing Authorities

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be designated by the NERC Operating Committee to serve as Interconnection Time Monitor.

R2. The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction Procedure.

R3. Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:

R3.1. The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or

R3.2. The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz Frequency Deviation (i.e. 20% of the Frequency Bias Setting).

R4. Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations.

R4.1. Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the termination of a Time Error Correction in progress.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

A. Introduction

1. **Title:** **Automatic Generation Control**

2. **Number:** BAL-005-0

3. **Purpose:**

   This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Generator Operators

   4.3. Transmission Operators

   4.4. Load Serving Entities

5. **Effective Date:** April 1, 2005

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.

R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

A. Introduction

1. **Title:** **Inadvertent Interchange**

2. **Number:** BAL-006-0

3. **Purpose:**

   This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

4. **Applicability:**

   4.1. Balancing Authorities.

5. **Effective Date** April 1, 2005

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.

R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators.

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.

R4. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following:

R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:

R4.1.1. The hourly values of Net Interchange Schedule.

R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange.

R4.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.

R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies).

R5. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy.

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Levels of Non Compliance

A Balancing Authority that neither submits a report to the Regional Reliability Organization Survey Contact, nor supplies a reason for not submitting the required data, by the 20th calendar day of the following month shall be considered non-compliant.

E. Regional Differences

1. MISO RTO Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Introduction

1. **Title:** **Sabotage Reporting**
2. **Number:** CIP-001-0
3. **Purpose:** Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.
4. **Applicability**
   - **4.1.** Reliability Coordinators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Transmission Operators.
   - **4.4.** Generator Operators.
   - **4.5.** Load Serving Entities.
5. **Effective Date:** April 1, 2005

A. Requirements

R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.

R2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.

B. Measures

Not specified.

C. Compliance

Not specified.

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

A. Introduction

1. **Title:** **Telecommunications**

2. **Number:** COM-001-0

3. **Purpose:** Each Reliability Coordinator, Transmission Operator and Balancing Authority needs adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Reliability Coordinators.

   4.4. NERCNet User Organizations.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:

R1.1. Internally.

R1.2. Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.

R1.3. With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.

R1.4. Where applicable, these facilities shall be redundant and diversely routed.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.

R3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.

R4. Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.

R6. Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, “NERCNet Security Policy.”

C. Measures

Not Specified.

D. Compliance

Not specified.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	October 3, 2005	Added “for” between “facilities” and “the” in Requirement 1.	Errata

Attachment 1-COM-001-0 — NERCnet Security Policy

Policy Statement

The purpose of this NERCnet Security Policy is to establish responsibilities and minimum requirements for the protection of information assets, computer systems and facilities of NERC and other users of the NERC frame relay network known as "NERCnet." The goal of this policy is to prevent misuse and loss of assets.

For the purpose of this document, information assets shall be defined as processed or unprocessed data using the NERCnet Telecommunications Facilities including network documentation. This policy shall also apply as appropriate to employees and agents of other corporations or organizations that may be directly or indirectly granted access to information associated with NERCnet.

The objectives of the NERCnet Security Policy are:

- To ensure that NERCnet information assets are adequately protected on a cost-effective basis and to a level that allows NERC to fulfill its mission.
- To establish connectivity guidelines for a minimum level of security for the network.
- To provide a mandate to all Users of NERCnet to properly handle and protect the information that they have access to in order for NERC to be able to properly conduct its business and provide services to its customers.

NERC's Security Mission Statement

NERC recognizes its dependency on data, information, and the computer systems used to facilitate effective operation of its business and fulfillment of its mission. NERC also recognizes the value of the information maintained and provided to its members and others authorized to have access to NERCnet. It is, therefore, essential that this data, information, and computer systems, and the manual and technical infrastructure that supports it, are secure from destruction, corruption, unauthorized access, and accidental or deliberate breach of confidentiality.

Implementation and Responsibilities

This section identifies the various roles and responsibilities related to the protection of NERCnet resources.

NERCnet User Organizations

Users of NERCnet who have received authorization from NERC to access the NERC network are considered users of NERCnet resources. To be granted access, users shall complete a User Application Form and submit this form to the NERC Telecommunications Manager.

Responsibilities

It is the responsibility of NERCnet User Organizations to:

- Use NERCnet facilities for NERC-authorized business purposes only.
- Comply with the NERCnet security policies, standards, and guidelines, as well as any procedures specified by the data owner.
- Prevent unauthorized disclosure of the data.
- Report security exposures, misuse, or non-compliance situations via Reliability Coordinator Information System or the NERC Telecommunications Manager.

- Protect the confidentiality of all user IDs and passwords.
- Maintain the data they own.
- Maintain documentation identifying the users who are granted access to NERCnet data or applications.
- Authorize users within their organizations to access NERCnet data and applications.
- Advise staff on NERCnet Security Policy.
- Ensure that all NERCnet users understand their obligation to protect these assets.
- Conduct self-assessments for compliance.

User Accountability and Compliance

All users of NERCnet shall be familiar and ensure compliance with the policies in this document.

Violations of the NERCnet Security Policy shall include, but not be limited to any act that:

- Exposes NERC or any user of NERCnet to actual or potential monetary loss through the compromise of data security or damage.
- Involves the disclosure of trade secrets, intellectual property, confidential information or the unauthorized use of data.

  Involves the use of data for illicit purposes, which may include violation of any law, regulation or reporting requirement of any law enforcement or government body.

A. Introduction

1. **Title:** **Communication and Coordination**
2. **Number:** COM-002-1
3. **Purpose:** To ensure Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective.
4. **Applicability**
   - **4.1.** Reliability Coordinators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Transmission Operators.
   - **4.4.** Generator Operators.
5. **Effective Date:** November 1, 2006

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.

R1.1. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Emergency Operations Planning**

2. **Number:** EOP-001-0

3. **Purpose:** Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. **Applicability**

   4.1. Balancing Authorities.

   4.2. Transmission Operators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

R3. Each Transmission Operator and Balancing Authority shall:

R3.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R3.3. Develop, maintain, and implement a set of plans for load shedding.

R3.4. Develop, maintain, and implement a set of plans for system restoration.

R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R4.1. Communications protocols to be used during emergencies.

R4.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R4.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R4.4. Staffing levels for the emergency.

R5. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.

R6. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R7. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R7.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R7.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R7.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R7.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframes

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-0.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: One of the applicable elements of Attachment 1-EOP-001-0 has not been addressed in the emergency plans.

2.2. Level 2: Two of the applicable elements of Attachment 1-EOP-001-0 have not been addressed in the emergency plans.

2.3. Level 3: Three of the applicable elements of Attachment 1-EOP-001-0 have not been addressed in the emergency plans.

2.4. Level 4: Four or more of the applicable elements of Attachment 1-EOP-001-0 have not been addressed in the emergency plans or a plan does not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

Attachment 1-EOP-001-0

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

A. Introduction

1. **Title**: **Capacity and Energy Emergencies**
2. **Number**: EOP-002-1
3. **Purpose**: To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
4. **Applicability**
   a. Balancing Authorities
   b. Reliability Coordinators
5. **Effective Date:** November 1, 2006

B. Requirements

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.

R2. Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

R6.1. Loading all available generating capacity.

R6.2. Deploying all available operating reserve.

R6.3. Interrupting interruptible load and exports.

R6.4. Requesting emergency assistance from other Balancing Authorities.

R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and

R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 7, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

R7.1. Manually shed firm load without delay to return its ACE to zero; and

R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.”

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.” The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff (See Attachment 1-IRO-006-0 “Transmission Loading Relief Procedure” for explanation of Transmission Service Priorities):

R9.1. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.

R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.

R9.3. The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

M1. At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the operation of a Balancing Authority or Reliability Coordinator when they have implemented their Capacity and Energy Emergency plans. Notification of an investigation must be made by the Regional Reliability Organization to the Balancing Authority or Reliability Coordinator being investigated as soon as possible, but no later than 60 days after the event. The Balancing Authority or Reliability Coordinator will be reviewed to determine if their Capacity and Energy Emergency Plans were appropriately followed (for a particular situation, not all of the steps may be effective or required).

M2. Evidence will be gathered to determine the level of communication between the Balancing Authority or Reliability Coordinator and other affected areas. An assessment will be made by the investigator(s) as to whether the level and timing of communication of system conditions and actions taken to relieve emergency conditions was acceptable and in conformance with the Capacity and Energy Emergency Plans.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One Calendar year without a violation from the time of the violation.

1.3. Data Retention

Each Balancing Authority and Reliability Coordinator is required to maintain operational data, logs, and voice recordings relevant to the implementation of the Capacity and Energy Emergency Plans for 60 days following the implementation. After an investigation is completed, the Regional Reliability Organization is required to keep the report of the investigation on file for two years.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: N/A.

2.3. Level 3: One or more of the actions of the Capacity and Energy Emergency Plans were not implemented resulting in a prolonged abnormal system condition.

2.4. Level 4: One or more of the actions of the Capacity and Energy Emergency Plans were not implemented resulting in a prolonged abnormal system condition and there was a delay or gap in communications.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

Attachment 1-EOP-002-0
Energy Emergency Alerts

Introduction

This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

   1.1. **Situations for initiating alert.** An Energy Emergency Alert may be initiated for the following reasons:

   - When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
   - The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **Alert 1 — All available resources in use.**

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **Alert 2 — Load management procedures in effect**.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  - Public appeals to reduce demand.
  - Voltage reduction.
  - Interruption of non-firm end use loads in accordance with applicable contracts[1].
  - Demand-side management.
  - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers**.**

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

[1] For emergency, not economic, reasons.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 Initiating inquiries on reevaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected

Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. **All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**

2. **All firm and nonfirm purchases were made regardless of cost.**

3. **All nonfirm sales were recalled within provisions of the sale agreement.**

4. **Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**

5. **Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

6. Operating Reserves being utilized.

Comments:

Reported By: **Organization:**

Title:

A. Introduction

1. **Title:** **Load Shedding Plans**

2. **Number:** EOP-003-0

3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.

R8. Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Disturbance Reporting**
2. **Number:** EOP-004-0
3. **Purpose:** Disturbances or unusual occurrences that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions, need to be studied and understood to minimize the likelihood of similar events in the future.
4. **Applicability**
   - **4.1.** Reliability Coordinators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Transmission Operators.
   - **4.4.** Generator Operators.
   - **4.5.** Load Serving Entities.
   - **4.6.** Regional Reliability Organizations.
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.

R2. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities.

R3. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.

R3.1. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.

R3.2. Applicable reporting forms are provided in Attachments 1-EOP-004-0 and 2-EOP-004-0.

R3.3. Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

R3.4. If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator

Operator, or Load Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.

R4. When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available to the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity immediately affected by the disturbance for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.

R5. The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Reliability Organization tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Reliability Organization shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Reliability Organization has taken to accelerate implementation.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	May 23, 2005	Fixed reference to attachments 1-EOP-004-0 and 2-EOP-004-0, Changed chart title 1-FAC-004-0 to 1-EOP-004-0, Fixed title of Table 1 to read 1-EOP-004-0, and fixed font.	Errata
0	July 6, 2005	Fixed email in Attachment 1-EOP-004-0 from info@nerc.com to esisac@nerc.com.	Errata
0	July 26, 2005	Fixed Header on page 8 to read EOP-004-0	Errata
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

Attachment 1-EOP-004-0
NERC Disturbance Report Form

Introduction

These disturbance reporting requirements apply to all Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load Serving Entities, and provide a common basis for all NERC disturbance reporting. The entity on whose system a reportable disturbance occurs shall notify NERC and its Regional Reliability Organization of the disturbance using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. Reports can be sent to NERC via email (esisac@nerc.com) by facsimile (609-452-9550) using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. If a disturbance is to be reported to the U.S. Department of Energy also, the responding entity may use the DOE reporting form when reporting to NERC. Note: All Emergency Incident and Disturbance Reports (Schedules 1 and 2) sent to DOE shall be simultaneously sent to NERC, preferably electronically at esisac@nerc.com.

The NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports are to be made for any of the following events:

1. The loss of a bulk power transmission component that significantly affects the integrity of interconnected system operations. Generally, a disturbance report will be required if the event results in actions such as:
   a. Modification of operating procedures.
   b. Modification of equipment (e.g. control systems or special protection systems) to prevent reoccurrence of the event.
   c. Identification of valuable lessons learned.
   d. Identification of non-compliance with NERC standards or policies.
   e. Identification of a disturbance that is beyond recognized criteria, i.e. three-phase fault with breaker failure, etc.
   f. Frequency or voltage going below the under-frequency or under-voltage load shed points.
2. The occurrence of an interconnected system separation or system islanding or both.
3. Loss of generation by a Generator Operator, Balancing Authority, or Load-Serving Entity — 2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection.
4. Equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below:
   a. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
   b. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.
5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.
6. Any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in:
   a. Sustained voltage excursions equal to or greater than ±10%, or
   b. Major damage to power system components, or
   c. Failure, degradation, or misoperation of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require operator intervention,

which did result in, or could have resulted in, a system disturbance as defined by steps 1 through 5 above.

7. An Interconnection Reliability Operating Limit (IROL) violation as required in reliability standard TOP-007.

8. Any event that the Operating Committee requests to be submitted to Disturbance Analysis Working Group (DAWG) for review because of the nature of the disturbance and the insight and lessons the electricity supply and delivery industry could learn.

NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report

☐ Check here if this is an Interconnection Reliability Operating Limit (IROL) violation report.

1.	Organization filing report.		
2.	Name of person filing report.		
3.	Telephone number.		
4.	Date and time of disturbance. Date:(mm/dd/yy) Time/Zone:		
5.	Did the disturbance originate in your system?	Yes ☐ No ☐	
6.	Describe disturbance including: cause, equipment damage, critical services interrupted, system separation, key scheduled and actual flows prior to disturbance and in the case of a disturbance involving a special protection or remedial action scheme, what action is being taken to prevent recurrence.		
7.	Generation tripped. MW Total List generation tripped		
8.	Frequency. Just prior to disturbance (Hz): Immediately after disturbance (Hz max.): Immediately after disturbance (Hz min.):		
9.	List transmission lines tripped (specify voltage level of each line).		
10.		FIRM	INTERRUPTIBLE
	Demand tripped (MW):		
	Number of affected Customers:		
	Demand lost (MW-Minutes):		
11.	Restoration time.	INITIAL	FINAL
	Transmission:		
	Generation:		
	Demand:		

Attachment 2-EOP-004-0
U.S. Department of Energy Disturbance Reporting Requirements

Introduction

The U.S. Department of Energy (DOE), under its relevant authorities, has established mandatory reporting requirements for electric emergency incidents and disturbances in the United States. DOE collects this information from the electric power industry on Form EIA-417 to meet its overall national security and Federal Energy Management Agency's Federal Response Plan (FRP) responsibilities. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE's Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. In addition, the data may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems.

Every Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity must use this form to submit mandatory reports of electric power system incidents or disturbances to the DOE Operations Center, which operates on a 24-hour basis, seven days a week. All other entities operating electric systems have filing responsibilities to provide information to the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity when necessary for their reporting obligations and to file form EIA-417 in cases where these entities will not be involved. EIA requests that it be notified of those that plan to file jointly and of those electric entities that want to file separately.

Special reporting provisions exist for those electric utilities located within the United States, but for whom Reliability Coordinator oversight responsibilities are handled by electrical systems located across an international border. A foreign utility handling U.S. Balancing Authority responsibilities, may wish to file this information voluntarily to the DOE. Any U.S.-based utility in this international situation needs to inform DOE that these filings will come from a foreign-based electric system or file the required reports themselves.

Form EIA-417 must be submitted to the DOE Operations Center if any one of the following applies (see Table 1-EOP-004-0 — Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies):

1. Uncontrolled loss of 300 MW or more of firm system load for more than 15 minutes from a single incident.
2. Load shedding of 100 MW or more implemented under emergency operational policy.
3. System-wide voltage reductions of 3 percent or more.
4. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system.
5. Actual or suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism, which target components of any security system. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.
6. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.
7. Fuel supply emergencies that could impact electric power system adequacy or reliability.
8. Loss of electric service to more than 50,000 customers for one hour or more.
9. Complete operational failure or shut-down of the transmission and/or distribution electrical system.

The initial DOE Emergency Incident and Disturbance Report (form EIA-417 – Schedule 1) shall be submitted to the DOE Operations Center within 60 minutes of the time of the system disruption.

Complete information may not be available at the time of the disruption. However, provide as much information as is known or suspected at the time of the initial filing. If the incident is having a critical impact on operations, a telephone notification to the DOE Operations Center (202-586-8100) is acceptable, pending submission of the completed form EIA-417. Electronic submission via an on-line web-based form is the preferred method of notification. However, electronic submission by facsimile or email is acceptable.

An updated form EIA-417 (Schedule 1 and 2) is due within 48 hours of the event to provide complete disruption information. Electronic submission via facsimile or email is the preferred method of notification. Detailed DOE Incident and Disturbance reporting requirements can be found at: http://www.eia.doe.gov/cneaf/electricity/page/form_417.html.

Table 1-EOP-004-0 Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies				
Incident No.	**Incident**	**Threshold**	**Report Required**	**Time**
1	Uncontrolled loss of Firm System Load	≥ 300 MW – 15 minutes or more	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
2	Load Shedding	≥ 100 MW under emergency operational policy	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
3	Voltage Reductions	3% or more – applied system-wide	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
4	Public Appeals	Emergency conditions to reduce demand	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
5	Physical sabotage, terrorism or vandalism	On physical security systems – suspected or real	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
6	Cyber sabotage, terrorism or vandalism	If the attempt is believed to have or did happen	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
7	Fuel supply emergencies	Fuel inventory or hydro storage levels ≤ 50% of normal	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
8	Loss of electric service	≥ 50,000 for 1 hour or more	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
9	Complete operation failure of electrical system	If isolated or interconnected electrical systems suffer total electrical system collapse	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
All DOE EIA-417 Schedule 1 reports are to be filed within 60-minutes after the start of an incident or disturbance All DOE EIA-417 Schedule 2 reports are to be filed within 48-hours after the start of an incident or disturbance				
All entities required to file a DOE EIA-417 report (Schedule 1 & 2) shall send a copy of these reports to NERC simultaneously, but no later than 24 hours after the start of the incident or disturbance.				
Incident No.	**Incident**	**Threshold**	**Report Required**	**Time**
1	Loss of major system component	Significantly affects integrity of interconnected system operations	NERC Prelim Final report	24 hour 60 day
2	Interconnected system separation or system islanding	Total system shutdown Partial shutdown, separation, or islanding	NERC Prelim Final report	24 hour 60 day
3	Loss of generation	≥ 2,000 – Eastern Interconnection ≥ 2,000 – Western Interconnection ≥ 1,000 – ERCOT Interconnection	NERC Prelim Final report	24 hour 60 day
4	Loss of firm load ≥15-minutes	Entities with peak demand ≥3,000: loss ≥300 MW All others ≥200MW or 50% of total demand	NERC Prelim Final report	24 hour 60 day
5	Firm load shedding	≥100 MW to maintain continuity of bulk system	NERC Prelim Final report	24 hour 60 day
6	System operation or operation actions resulting in:	• Voltage excursions ≥10% • Major damage to system components • Failure, degradation, or misoperation of SPS	NERC Prelim Final report	24 hour 60 day
7	IROL violation	Reliability standard TOP-007.	NERC Prelim Final report	72 hour 60 day
8	As requested by ORS Chairman	Due to nature of disturbance & usefulness to industry (lessons learned)	NERC Prelim Final report	24 hour 60 day
All NERC Operating Security Limit and Preliminary Disturbance reports will be filed within 24 hours after the start of the incident. If an entity must file a DOE EIA-417 report on an incident, which requires a NERC Preliminary report, the Entity may use the DOE EIA-417 form for both DOE and NERC reports.				
Any entity reporting a DOE or NERC incident or disturbance has the responsibility to also notify its Regional Reliability Organization.				

A. Introduction

1. **Title:** **System Restoration Plans**

2. **Number:** EOP-005-0

3. **Purpose:** To ensure plans, procedures, and resources are available to restore the electric system to a normal condition in the event of a partial or total shut down of the system

4. **Applicability**

   4.2. Transmission Operators.

   4.3. Balancing Authorities.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005-0 in developing a restoration plan.

R2. Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall correct deficiencies found during the simulated restoration exercises.

R3. Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.

R4. Each Transmission Operator shall coordinate its restoration plans with Balancing Authorities within its area, its Reliability Coordinator, and neighboring Transmission Operators and Balancing Authorities.

R5. Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.

R6. Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.

R7. Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.

R8. Each Transmission Operator shall ensure the availability and location of black start capability within its area to meet the needs of the restoration plan.

R9. Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.

R9.1. The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).

R9.2. The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators online, or load shedding.

R9.3. The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments as needed to facilitate the restoration. The affected Balancing Authorities shall make all attempts to maintain the adjusted Interchange Schedules, whether generation control is manual or automatic.

R9.4. The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.

R9.5. The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:

R9.5.1. Voltage, frequency, and phase angle permit.

R9.5.2. The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are considered.

R9.5.3. Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.

R9.5.4. Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Self-Certification: Each Transmission Operator shall annually self-certify to the Regional Reliability Organization that the following criteria have been met:

1.1.1 The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.

1.1.2 A set of procedures for annual review for simulating and, where practical, actual testing and verification of the restoration plan resources and procedures.

1.1.3 Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.

1.1.4 Any significant changes to the restoration plan must be reported to the Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Transmission Operator must have its plan to reestablish its electric system available for a review by the Regional Reliability Organization at all times.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Plan exists but is not reviewed annually.

2.2. Level 2: Plan exists but does not address one of the elements listed in Attachment 1-EOP-005-0.

2.3. Level 3: N/A.

2.4. Level 4: Plan exists but does not address two or more of the requirements in Attachment 1-EOP-005-0, or there is no restoration plan in place.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Attachment 1-EOP-005-0

Elements for Consideration in Development of Restoration Plans

The Restoration Plan must consider the following requirements, as applicable:

1. Plan and procedures outlining the relationships and responsibilities of the personnel necessary to implement system restoration.
2. The provision for a reliable black-start capability plan including: fuel resources for black start power for generating units, available cranking and transmission paths, and communication adequacy and protocol and power supplies.
3. The plan must account for the possibility that restoration cannot be completed as expected.
4. The necessary operating instructions and procedures for synchronizing areas of the system that have become separated.
5. The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.
6. A set of procedures for simulating and, where practical, actually testing and verifying the plan resources and procedures (at least every three years).
7. Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.
8. The functions to be coordinated with and among Reliability Coordinators and neighboring Transmission Operators. (The plan should include references to coordination of actions among neighboring Transmission Operators and Reliability Coordinators when the plans are implemented.)
9. Notification shall be made to other operating entities as the steps of the restoration plan are implemented.

A. Introduction

1. **Title:** **Reliability Coordination – System Restoration**

2. **Number:** EOP-006-0

3. **Purpose:** The Reliability Coordinator must have a coordinating role in system restoration to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.

4. **Applicability**

   4.1. Reliability Coordinator.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Reliability Coordinator shall be aware of the restoration plan of each Transmission Operator in its Reliability Coordinator Area in accordance with NERC and regional requirements.

R2. The Reliability Coordinator shall monitor restoration progress and coordinate any needed assistance.

R3. The Reliability Coordinator shall have a Reliability Coordinator Area restoration plan that provides coordination between individual Transmission Operator restoration plans and that ensures reliability is maintained during system restoration events.

R4. The Reliability Coordinator shall serve as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and Transmission Operators or Balancing Authorities not immediately involved in restoration.

R5. Reliability Coordinators shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to cause a Burden on adjacent Transmission Operator, Balancing Authority, or Reliability Coordinator Areas.

R6. The Reliability Coordinator shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Establish, Maintain, and Document a Regional Blackstart Capability Plan.**

2. **Number:** EOP-007-0

3. **Purpose:** A system Blackstart Capability Plan (BCP) is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional System Restoration Plans (SRP).

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall establish and maintain a system BCP, as part of an overall coordinated Regional SRP. The Regional SRP shall include requirements for verification through analysis how system blackstart generating units shall perform their intended functions and shall be sufficient to meet SRP expectations. The Regional Reliability Organization shall coordinate with and among other Regional Reliability Organizations as appropriate in the development of its BCP. The BCP shall include:

- **R1.1.** A requirement to have a database that contains all blackstart generators[1] designated for use in an SRP within the respective areas. This database shall be updated on an annual basis. The database shall include the name, location, megawatt capacity, type of unit, latest date of test, and starting method.

- **R1.2.** A requirement to demonstrate that blackstart units perform their intended functions as required in the Regional SRP. This requirement can be met through either simulation or testing. The BCP must consider the availability of designated BCP units and initial transmission switching requirements.

- **R1.3.** Blackstart unit testing requirements including, but not limited to:

  - **R1.3.1.** Testing frequency (minimum of one third of the units each year).

  - **R1.3.2.** Type of test required, including the requirement to start when isolated from the system.

  - **R1.3.3.** Minimum duration of tests.

- **R1.4.** A requirement to review and update the Regional BCP at least every five years.

R2. The Regional Reliability Organization shall provide documentation of its system BCPs to NERC within 30 calendar days of a request.

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[1] A unit cannot be considered a blackstart unit unless it has met the regional blackstart requirements. It is expected that if a unit fails a test, that unit will be fixed and retested within a timeframe established by the Regional Reliability Organization in accordance with the Regional Blackstart Capability plan or that unit will no longer be considered a blackstart unit.

C. Measures

M1. The Regional Reliability Organization's BCP shall include all four of the requirements in Reliability Standard EOP-007-0_R1.

M2. The Regional Reliability Organization shall have evidence it provided its BCP in accordance with Reliability Standard EOP-007-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Current Regional BCP: on request (30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: The Regional Reliability Organization's Blackstart Capability Plan was incomplete in one of the four requirements defined above in Reliability Standard EOP-007-0_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's Blackstart Capability Plan was not provided (Reliability Standard EOP-007-0_R1), or was incomplete in two or more of the four requirements defined above in Reliability Standard EOP-007-0_R1.

E. Regional Differences

1. None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Plans for Loss of Control Center Functionality**
2. **Number:** EOP-008-0
3. **Purpose:** Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable.
4. **Applicability**
   - **4.1.** Transmission Operators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Reliability Coordinators.
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:

- **R1.1.** The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.
- **R1.2.** The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.
- **R1.3.** The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.
- **R1.4.** The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.
- **R1.5.** The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.
- **R1.6.** The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.
- **R1.7.** The plan shall be reviewed and updated annually.
- **R1.8.** Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.

C. Measures

M1. Evidence that the Reliability Coordinator, Transmission Operator or Balancing Authority has developed and documented a current contingency plan to continue the monitoring and operation of the electrical equipment under its control to maintain Bulk Electrical System reliability if its primary control facility becomes inoperable.

D. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Periodic Review: Review and evaluate the plan for loss of primary control facility contingency as part of the three-year on-site audit process. The audit must include a demonstration of the plan by the Reliability Coordinator, Transmission Operator, and Balancing Authority.

Reset: One calendar year.

1.3. Data Retention

The contingency plan for loss of primary control facility must be available for review at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: NA

2.2. Level 2: A contingency plan has been implemented and tested, but has not been tested in the past year or there are no records of shift operating personnel training.

2.3. Level 3: A contingency plan has been implemented, but does not include all of the elements contained in Requirements R1.1–R1.8.

2.4. Level 4: A contingency plan has not been developed, implemented, and tested.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Documentation of Blackstart Generating Unit Test Results**

2. **Number:** EOP-009-0

3. **Purpose:** A system Blackstart Capability Plan (BCP) is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional System Restoration Plans.

4. **Applicability:**

   4.1. Generator Operator

   4.2. Generator Owner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the BCP as required in the Regional BCP (Reliability Standard EOP-007-0_R1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met Regional BCP requirements.

R2. The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.

C. Measures

M1. The Generator Operator shall have evidence it provided the test results specified in Reliability Standard EOP-009-0R1 as specified in Reliability Standard EOP-009-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Current test results: to the Regional Reliability Organization and upon request to NERC (30 calendar days).

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None

2. **Levels of Non-Compliance**

   2.1. Level 1: Startup and operation testing of each blackstart generating unit was performed, but the documentation was incomplete.

   2.2. Level 2: Not applicable.

2.3. Level 3: Startup and operation testing of a blackstart generating unit was only partially performed.

2.4. Level 4: Startup and operation testing of each blackstart generating unit was not performed.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Facility Connection Requirements**
2. **Number:** FAC-001-0
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners must establish facility connection and performance requirements.
4. **Applicability:**
   - **4.1.** Transmission Owner
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility connection requirements shall address connection requirements for:

R1.1. Generation facilities,

R1.2. Transmission facilities, and

R1.3. End-user facilities

R2. The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.

R2.1.2. Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.

R2.1.3. Voltage level and MW and MVAR capacity or demand at point of connection.

R2.1.4. Breaker duty and surge protection.

R2.1.5. System protection and coordination.

R2.1.6. Metering and telecommunications.

R2.1.7. Grounding and safety issues.

R2.1.8. Insulation and insulation coordination.

R2.1.9. Voltage, Reactive Power, and power factor control.

R2.1.10. Power quality impacts.

R2.1.11. Equipment Ratings.

R2.1.12. Synchronizing of facilities.

R2.1.13. Maintenance coordination.

R2.1.14. Operational issues (abnormal frequency and voltages).

R2.1.15. Inspection requirements for existing or new facilities.

R2.1.16. Communications and procedures during normal and emergency operating conditions.

R3. The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Reliability Organization, and NERC on request (five business days).

C. Measures

M1. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all the requirements stated in Reliability Standard FAC-001-0_R1.

M2. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all requirements stated in Reliability Standard FAC-001-0_R2.

M3. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all the requirements stated in Reliability Standard FAC-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (five business days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Facility connection requirements were provided for generation, transmission, and end-user facilities, per Reliability Standard FAC-001-0_R1, but the document(s) do not address all of the requirements of Reliability Standard FAC-001-0_R2.

2.2. Level 2: Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, but the document(s) provided address all of the requirements of Reliability Standard FAC-001-0_R2.

2.3. Level 3: Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, and the document(s) provided do not address all of the requirements of Reliability Standard FAC-001-0_R2.

2.4. Level 4: No document on facility connection requirements was provided per Reliability Standard FAC-001-0_R3.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Coordination of Plans For New Generation, Transmission, and End-User Facilities**

2. **Number:** FAC-002-0

3. **Purpose:** To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Transmission Owner

   4.3. Distribution Provider

   4.4. Load-Serving Entity

   4.5. Transmission Planner

   4.6. Planning Authority

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:

R1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.

R1.2. Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.

R1.3. Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.

R1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0.

R1.5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

R2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

C. Measures

M1. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider's documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard FAC-002-0_R1.

M2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each have evidence of its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard FAC-002-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: RRO.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

Evidence of the assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems: Three years.

1.4. Additional Compliance Information

None

2. Levels of Non-Compliance

2.1. Level 1: Assessments of the impacts of new facilities were provided, but were incomplete in one or more requirements of Reliability Standard FAC-002_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Assessments of the impacts of new facilities were not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Transmission Vegetation Management Program**

2. **Number:** FAC-003-1

3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).

4. **Applicability:**

   4.1. Transmission Owner.

   4.2. Regional Reliability Organization.

   4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.

5. **Effective Dates:**

   5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.

   5.2. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.

B. Requirements

R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications[1].

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.

R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future

[1] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These 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 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.

R1.4. Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.

R3.2. The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

C. Measures

M1. The Transmission Owner has a documented TVMP, as identified in Requirement 1.

M1.1. The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner's TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.

M1.4. The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner's standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO's designee, as identified in Requirement 3.

M4. The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

RRO

NERC

1.2. Compliance Monitoring Period and Reset

One calendar Year

1.3. Data Retention

Five Years

1.4. Additional Compliance Information

The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.

2. Levels of Non-Compliance

2.1. Level 1:

2.1.1. The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;

2.1.2. Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;

2.1.3. The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.

2.2. Level 2:

2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;

2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.

2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.

2.3. Level 3:

2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;

2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;

2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.

2.4. Level 4:

2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;

2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	TBA	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	01/20/06

A. Introduction

1. **Title:** **Methodologies for Determining Electrical Facility Ratings**
2. **Number:** FAC-004-0
3. **Purpose:** To ensure that electrical facilities used in the transmission and storage of electricity are rated in compliance with applicable Regional Reliability Organization requirements.
4. **Applicability:**
   - **4.1.** Transmission Owner
   - **4.2.** Generator Owner
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner and Generator Owner shall each document the methodology(ies) used to determine its electrical equipment and Facility Ratings. Further, the methodology(ies) shall comply with applicable Regional Reliability Organization requirements. The documentation shall address and include

R1.1. The methodology(ies) used to determine equipment and Facility Rating of the items listed for both normal and emergency conditions:

R1.1.1. Transmission circuits.

R1.1.2. Transformers.

R1.1.3. Series and shunt reactive elements.

R1.1.4. Terminal equipment (e.g., switches, breakers, current transformers, etc).

R1.1.5. VAR compensators.

R1.1.6. High voltage direct current converters.

R1.1.7. Any other device listed as a Limiting Element.

R1.2. The Rating of a facility shall not exceed the Rating(s) of the most Limiting Element(s) in the circuit, including terminal connections and associated equipment.

R1.3. In cases where protection systems and control settings constitute a loading limit on a facility, this limit shall become the Rating for that facility.

R1.4. Ratings of jointly-owned and jointly-operated facilities shall be coordinated among the joint owners and joint operators resulting in a single set of Ratings.

R1.5. The documentation shall identify the assumptions used to determine each of the equipment and Facility Ratings, including references to industry Rating practices and standards (e.g., ANSI, IEEE, etc.). Seasonal Ratings and variations in assumptions shall be included.

R2. The Transmission Owner and Generator Owner shall provide documentation of the methodology(ies) used to determine its transmission equipment and Facility Ratings to the Regional Reliability Organization(s) and NERC on request (30 calendar days).

C. Measures

M1. The Transmission Owner or Generator Owner shall provide documentation that the methodology(ies) used for determining equipment and Facility Ratings meets the requirements of Standard FAC-004-0_R1 as specified in Standard FAC-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Equipment and Facility Ratings methodology(ies) do not address one of the five elements listed in Reliability Standard FAC-004-0_R1.

2.2. Level 2: N/A.

2.3. Level 3: Equipment and Facility Ratings methodology(ies) do not address two of the five elements listed in Reliability Standard FAC-004-0_R1.

2.4. Level 4: Equipment and Facility Ratings methodology(ies) do not address three or more of the five elements listed in Reliability Standard FAC-004-0_R1, or no equipment and Facility Rating methodology was provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	September 26, 2005	Fixed reference in M1 from FAC-004-0_R2 to FAC-004-0_R1	Errata

A. Introduction

1. **Title:** **Electrical Facility Ratings for System Modeling**

2. **Number:** FAC-005-0

3. **Purpose:** To ensure that electrical facilities used in the transmission and storage of electricity are Rated in compliance with applicable Regional Reliability Organization requirements.

4. **Applicability:**

    4.1. Transmission Owner

    4.2. Generator Owner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The transmission Owner, and Generator Owner shall each have on file or be able to readily provide, a document or database identifying the Normal and Emergency Ratings of all of its transmission facilities (e.g., lines, transformers, terminal equipment, and storage devices) that are part of the interconnected transmission systems. Seasonal variations in Ratings shall be included as appropriate.

R1.1. The Ratings shall be consistent with the entity's methodology(ies) for determining Facility Ratings and shall be updated as facility changes occur.

R2. The Transmission Owner and Generator Owner shall provide the Normal and Emergency Facility Ratings of all its transmission facilities to the Regional Reliability Organization(s) and NERC on request (30 calendar days).

C. Measures

M1. The Transmission Owner and Generator Owner shall provide documentation of its facility Ratings as specified in Reliability Standard FAC-005-0_R1 and Standard FAC-005-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

    1.1. Compliance Monitoring Responsibility

    Compliance Monitor: Regional Reliability Organization.

    1.2. Compliance Monitoring Period and Reset Timeframe

    On request (30 calendar days.)

    1.3. Data Retention

    None specified.

    1.4. Additional Compliance Information

    None.

2. **Levels of Non-Compliance**

    2.1. Level 1: Facility Ratings were incomplete or the methodology(ies) were inconsistently applied in one facility type.

2.2. Level 2: Facility Ratings were incomplete or the methodology(ies) were inconsistently applied in two facility types.

2.3. Level 3: Facility Ratings were incomplete or the methodology(ies) were inconsistently applied in three or more facility types.

2.4. Level 4: Facility Ratings were not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Facility Ratings Methodology**

2. **Number:** FAC-008-1

3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Transmission Owner

   4.2. Generator Owner

5. **Effective Date:** August 7, 2006

B. Requirements

R1. The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities. The methodology shall include all of the following:

R1.1. A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

R1.2. The method by which the Rating (of major BES equipment that comprises a Facility) is determined.

R1.2.1. The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

R1.2.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

R1.3. Consideration of the following:

R1.3.1. Ratings provided by equipment manufacturers.

R1.3.2. Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).

R1.3.3. Ambient conditions.

R1.3.4. Operating limitations.

R1.3.5. Other assumptions.

R2. The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.

R3. If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the

Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

C. Measures

M1. The Transmission Owner and Generator Owner shall each have a documented Facility Ratings Methodology that includes all of the items identified in FAC-008 Requirement 1.1 through FAC-008 Requirement 1.3.5.

M2. The Transmission Owner and Generator Owner shall each have evidence it made its Facility Ratings Methodology available for inspection within 15 business days of a request as follows:

M2.1 The Reliability Coordinator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Reliability Coordinator Area.

M2.2 The Transmission Operator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its portion of the Reliability Coordinator Area.

M2.3 The Transmission Planner shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Transmission Planning Area.

M2.4 The Planning Authority shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Planning Authority Area.

M3. If the Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides documented comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall have evidence that it provided a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor at least once every three years. New Transmission Owners and Generator Owners shall each demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each keep all superseded portions of its Facility Ratings Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Facility Ratings Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall each make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Facility Ratings Methodology

1.4.2 Superseded portions of its Facility Ratings Methodology that had been replaced, changed or revised within the past 12 months

1.4.3 Documented comments provided by a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Authority on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings methodology, and the associated responses

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if any of the following conditions exists:

2.1.1 The Facility Ratings Methodology does not contain a statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.1.2 The Facility Ratings Methodology does not address one of the required equipment types identified in FAC-008 R1.2.1.

2.1.3 No evidence of responses to a Reliability Coordinator's, Transmission Operator, Transmission Planner, or Planning Authority's comments on the Facility Ratings Methodology.

2.2. Level 2: The Facility Ratings Methodology is missing the assumptions used to determine Facility Ratings or does not address two of the required equipment types identified in FAC-008 R1.2.1.

2.3. Level 3: The Facility Ratings Methodology does not address three of the required equipment types identified in FAC-008-1 R1.2.1.

2.4. Level 4: The Facility Ratings Methodology does not address both Normal and Emergency Ratings or the Facility Ratings Methodology was not made available for inspection within 15 business days of receipt of a request.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	01/01/05	1. Lower cased the word "draft" and "drafting team" where appropriate. 2. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 3. Changed "Timeframe" to "Time	01/20/05

		Frame” and “twelve” to “12” in item D, 1.2.	

A. Introduction

1. **Title:** **Establish and Communicate Facility Ratings**
2. **Number:** FAC-009-1
3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   - **4.1.** Transmission Owner
   - **4.2.** Generator Owner
5. **Effective Date:** October 7, 2006

B. Requirements

R1. The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings Methodology.

R2. The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

C. Measures

M1. The Transmission Owner and Generator Owner shall each be able to demonstrate that it developed its Facility Ratings consistent with its Facility Ratings Methodology.

M1.1 The Transmission Owner's and Generator Owner's Facility Ratings shall each include ratings for its solely and jointly owned Facilities including new Facilities, existing Facilities, modifications to existing Facilities and re-ratings of existing Facilities.

M2. The Transmission Owner and Generator Owner shall each have evidence that it provided its Facility Ratings to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January–December) and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall retain audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Facility Ratings Methodology

1.4.2 Facility Ratings

1.4.3 Evidence that Facility Ratings were distributed

1.4.4 Distribution schedules provided by entities that requested Facility Ratings

2. Levels of Non-Compliance

2.1. Level 1: Not all requested Facility Ratings associated with existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.

2.2. Level 2: Not all Facility Ratings associated with new Facilities, modifications to existing Facilities, and re-ratings of existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.

2.3. Level 3: Facility Ratings provided were not developed consistent with the Facility Ratings Methodology.

2.4. Level 4: No Facility Ratings were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), or Transmission Operator(s) in accordance with their respective schedules.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Lower cased the word “draft” and “drafting team” where appropriate. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06

A. Introduction

1. **Title:** **Transfer Capability Methodology**

2. **Number:** FAC-012-1

3. **Purpose:** To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

   4.2. Planning Authority required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

5. **Effective Date:** August 7, 2006

B. Requirements

R1. The Reliability Coordinator and Planning Authority shall each document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). The Transfer Capability Methodology shall include all of the following:

R1.1. A statement that Transfer Capabilities shall respect all applicable System Operating Limits (SOLs).

R1.2. A definition stating whether the methodology is applicable to the planning horizon or the operating horizon.

R1.3. A description of how each of the following is addressed, including any reliability margins applied to reflect uncertainty with projected BES conditions:

R1.3.1. Transmission system topology

R1.3.2. System demand

R1.3.3. Generation dispatch

R1.3.4. Current and projected transmission uses

R2. The Reliability Coordinator shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

R2.1. Each Adjacent Reliability Coordinator and each Reliability Coordinator that indicated a reliability-related need for the methodology.

R2.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R2.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R3. The Planning Authority shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

R3.1. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R3.2. Each Adjacent Planning Authority and each Planning Authority that indicated a reliability-related need for the methodology.

R3.3. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4. If a recipient of the Transfer Capability Methodology provides documented technical comments on the methodology, the Reliability Coordinator or Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability Methodology and, if no change will be made to that Transfer Capability Methodology, the reason why.

C. Measures

M1. The Planning Authority and Reliability Coordinator's methodology for determining Transfer Capabilities shall each include all of the items identified in FAC-012 Requirement 1.1 through Requirement 1.3.4.

M2. The Reliability Coordinator shall have evidence it issued its Transfer Capability Methodology in accordance with FAC-012 Requirement 2 through Requirement R2.3.

M3. The Planning Authority shall have evidence it issued its Transfer Capability Methodology in accordance with FAC-012 Requirement 3 through Requirement 3.3.

M4. If the recipient of the Transfer Capability Methodology provides documented comments on its technical review of that Transfer Capability Methodology, the Reliability Coordinator or Planning Authority that distributed that Transfer Capability Methodology shall have evidence that it provided a written response to that commenter in accordance with FAC-012 Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Timeframe

Each Planning Authority and Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities and Reliability Coordinators shall each demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Planning Authority and Reliability Coordinator shall each keep all superseded portions to its Transfer Capability Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Transfer Capability Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority and Reliability Coordinator shall each make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Transfer Capability Methodology.

1.4.2 Superseded portions of its Transfer Capability Methodology that have been made within the past 12 months.

1.4.3 Documented comments provided by a recipient of the Transfer Capability Methodology on its technical review of the Transfer Capability Methodology, and the associated responses.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The Transfer Capability Methodology is missing any one of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4.

2.1.2 No evidence of responses to a recipient's comments on the Transfer Capability Methodology.

2.2. Level 2: The Transfer Capability Methodology is missing a combination of two of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4, or a combination thereof.

2.3. Level 3: The Transfer Capability Methodology is missing a combination of three or more of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4.

2.4. Level 4: The Transfer Capability Methodology was not issued to all of the required entities.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Lower cased the word "draft" and "drafting team" where appropriate. 2. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06

A. Introduction

1. **Title:** **Establish and Communicate Transfer Capabilities**

2. **Number:** FAC-013-1

3. **Purpose:** To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

   4.2. Planning Authority required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

5. **Effective Date:** October 7, 2006

B. Requirements

R1. The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.

R2. The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a reliability-related need for such Transfer Capabilities and make a written request that includes a schedule for delivery of such Transfer Capabilities as follows:

R2.1. The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area.

R2.2. The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.

C. Measures

M1. The Reliability Coordinator and Planning Authority shall each be able to demonstrate that it developed its Transfer Capabilities consistent with its Transfer Capability Methodology.

M2. The Reliability Coordinator and Planning Authority shall each have evidence that it provided its Transfer Capabilities in accordance with schedules supplied by the requestors of such Transfer Capabilities.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility
   Regional Reliability Organization

   1.2. Compliance Monitoring Period and Reset Timeframe

   The Reliability Coordinator and Planning Authority shall each verify compliance through self-certification submitted to the Compliance Monitor annually. The Compliance

Monitor may conduct a targeted audit once in each calendar year (January–December) and an investigation upon a complaint to assess compliance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Planning Authority and Reliability Coordinator shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority and Reliability Coordinator shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Transfer Capability Methodology.

1.4.2 Inter-regional and Intra-regional Transfer Capabilities.

1.4.3 Evidence that Transfer Capabilities were distributed.

1.4.4 Distribution schedules provided by entities that requested Transfer Capabilities.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not all requested Transfer Capabilities were provided in accordance with their respective schedules.

2.3. Level 3: Transfer Capabilities were not developed consistent with the Transfer Capability Methodology.

2.4. Level 4: No requested Transfer Capabilities were provided in accordance with their respective schedules.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” 4. Added or removed “periods.”	01/20/05

A. Introduction

1. **Title:** **Interchange Transaction Tagging**

2. **Number:** INT-001-0

3. **Purpose:**

   To ensure that Interchange Transactions, certain Interchange Schedules, and intra-Balancing Authority Area transfers using Point-to-Point Transmission Service are Tagged in adequate time to allow the transactions to be assessed for reliability impacts by the affected Reliability Coordinators, Transmission Service Providers, and Balancing Authorities, and to allow adequate time for implementation.

4. **Applicability:**

   4.1. Purchase-Selling Entities.

   4.2. Balancing Authorities.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Load-serving Purchasing-Selling Entity shall be responsible for ensuring Tags are submitted for:

R1.1. All Interchange Transactions that are between Balancing Authority Areas

R1.2. All transfers that are entirely within a Balancing Authority Area using Point-to-Point Transmission Service (including all grandfathered and "non-Order 888" Point-to-Point Transmission Service).

R1.3. All Dynamic Schedules at the expected average MW profile for each hour.

R2. The Sink Balancing Authority shall be responsible for ensuring a Tag is provided:

R2.1. If a Purchasing-Selling Entity is not involved in the Transaction, such as delivery from a jointly owned generator.

R2.2. To replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements. If the duration of the Emergency Transaction to replace the generation loss is less than 60 minutes, then the Transaction shall be exempt from Tagging.

R2.3. All bilateral inadvertent interchange payback.

R3. The Purchasing Selling Entity responsible for submitting the Tag shall submit all Tags to the Sink Balancing Authority according to timing tables in Attachment 1-INT-001-0.

R4. The Balancing Authority or Purchasing-Selling Entity responsible for submitting the Tag shall include the reliability data listed in Attachment 2-INT-001-0 in the Tag.

R5. Each Purchasing-Selling Entity with title to an Interchange Transaction shall have, or shall arrange to have, personnel directly and immediately available for notification of Interchange Transaction changes. These personnel shall be available from the time that the title to the Interchange Transaction is acquired until the Interchange Transaction has been completed.

C. Measures

M1. A Balancing Authority shall provide documentation to show all scheduled interchanges between Balancing Authority Areas were Tagged.

D. Compliance

Not Specified.

E. Regional Differences

1. WECC Tagging Dynamic Schedules and Inadvertent Payback Waiver effective on November 21, 2002.
2. MISO Energy Flow Information Waiver effective on July 16, 2003.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

Attachment 1-INT-001-0 — Tag Submission and Response Timetables for New Transactions

Eastern Interconnection – New Transactions

The table below represents the Tag submission and assessment deadlines within the Eastern Interconnection. These are default requirements; some regulatory or provincially-approved provider practices may have requirements that are more stringent. Under these instances, the more restrictive criteria shall be adhered to. The table describes the various minimum submission and assessment timing requirements.

Table 1: Eastern Interconnection – Timing Requirements

Transaction Duration	PSE Submit Deadline*	Actual Tag Submission Time	Provider Assessment Time	Time to Start of Transaction
Less than 24 Hours	20 Minutes prior to start	≤1 Hour prior to start	≤ 10 Minutes from Tag receipt	≥ 10 Min
		>1 to <4 hours prior to start	≤20 Minutes from Tag receipt	≥ 40 Min
		≥ 4 Hours prior to start	≤ 2 Hours from Tag receipt	≥ 2 Hours
24 Hours or longer	4 Hours prior to start	Any	≤ 2 Hours from Tag receipt	≥ 2 Hours
*Start time references are for start of the Transaction not the start of the Ramp.				

Tag submission timing requirements are based on the duration of the Transaction. Tags representing Transactions that run for less that one day (24 hours) must be submitted at least 20 minutes prior to the start of the Transaction (excluding Ramp time). Tags representing Transactions running for one day or more (24 hours or more) must be submitted at least four hours prior to the start. Tags submitted that meet these requirements shall be considered "on-time" and may be granted conditional approval. Tags submitted that do not meet these requirements shall be considered "late," and consequently will be denied if not explicitly approved by all parties.

Tag assessment timing requirements are based on the submission time of the Tag, as well as the duration. Hourly Tags submitted one hour or less prior to start must be evaluated in ten minutes. Hourly Tags submitted more than one hour but less than four hours prior to start must be evaluated in 20 minutes. Tags of a duration less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. Tags of duration 24 hours or more must be evaluated in two hours.

1) Eastern Interconnection — Reallocation During a Transmission Loading Relief (TLR) Event

During a NERC TLR event, Transactions may be submitted to replace existing Transactions with a lower transmission priority. The new Transaction Tag must be received no later than 35 minutes prior to the top of the hour to allow time for Reliability Coordinator to assess the impact of reallocation.

Western Interconnection – New Transactions

The table below represents the Tag submission and assessment deadlines within the Western Interconnection. These are default requirements. The tables describe the various minimum submission and assessment timing requirements.

Table 2: Western Interconnection – Timing Requirements

Transaction Start/Submittal Time	Late Status Deadline	Actual Tag Submission Time*	Provider Assessment Time	Approval/ Denial Notes	Time to Start of Transaction*
Start 00:00 next day or beyond when submitted prior to 18:00 of the current day	15:00 day prior to start	Any	3 hours	Passive approval if submitted before deadline, else passive denial. Deferred denial	≥ 6 Hours
Start 00:00 next day and submitted between 18:00 and 23:59:59 on day prior to start – OR – start within current day		≥ 4 Hours prior to start	2 Hours from Tag receipt	Passive approval Deferred denial	≥ 2 Hours
		<4 Hours to ≥1 Hour prior to start	20 minutes from Tag receipt	Passive approval Deferred denial	≥ 40 Min
		<1 hour to ≥30 minutes prior to start	10 minutes from Tag receipt	Passive approval Deferred denial	≥ 20 Min
		<30 minutes to ≥20 minutes prior to start	10 minutes from Tag receipt	Passive approval Deferred denial	≥ 10 Min
	20 minutes prior to start	<20 minutes prior to start	5 minutes from Tag receipt	Passive denial. Deferred denial	Submission time minus maximum time of 5 minutes

Notes/Clarification:

All clock times are in Pacific Prevailing Time (PPT).

Tags falling under the criteria in the first row are deemed pre-schedule Tags.

Tags falling under the criteria in the remaining rows are deemed real-time Tags.

Pre-schedule Tags submitted between 15:00 and 18:00 will be assigned LATE composite status.

Real-time Tags submitted after 20 minutes prior to the start of the Transaction will be assigned LATE composite status.

*Start-time references are for start of the Transaction, not the start of the Ramp.

Tag submission timing requirements are based on the type and duration of the Transaction. Tags representing Transactions that run for less that one day (24 hours) within the current day must be submitted at least 20 minutes prior to the start of the Transaction (excluding Ramp time). Tags representing Transactions that are pre-scheduled to start the next day must be submitted by 1500 PST the day prior to the day the Transaction is to start. Tags submitted that meet these requirements shall be considered “on-time” and may be granted conditional approval. Tags submitted that do not meet these requirements shall be considered “late,” and consequently will be denied if not explicitly approved by all parties.

Tag assessment timing requirements are based on the submission time of the Tag, as well as the duration. Hourly Tags submitted one hour or less prior to start must be evaluated in ten minutes. Hourly Tags submitted more than one hour but less than four hours prior to start must be evaluated in 20 minutes. Tags of a duration less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. Tags submitted for pre-scheduled service starting the next day or a future day must be evaluated in three hours.

Attachment 2-INT-001-0 — Required Tag Data

The following is the reliability information necessary to assess a Transaction:

1. Physical path — the description of physically scheduling parties, always containing a generation segment, at least one transmission segment, and a Load segment.
2. Generation — the physical characteristics of the energy source.
3. Resource service point — the physical point at which the energy is being generated. This may vary in granularity, depending on local practices.
4. Energy profile — energy to be produced by the generator for each time segment of the Transaction.
5. Transmission — the physical characteristics of a wheel (import, export, or through).
6. Transmission Service Provider — the identity of the Transmission Service Provider that is wheeling the energy.
7. Point of receipt — valid point of receipt for scheduled transmission reservation.
8. Point of delivery — valid point of delivery for scheduled transmission reservation.
9. Scheduling entity(ies) — entities that are physically scheduling interchange on behalf of the Transmission Service Provider in order to provide wheeling services. Typically this is the Balancing Authority providing a service for the Transmission Service Provider, but several Balancing Authorities may be supporting a regional transmission service.
10. Loss provision — the manner in which losses are accounted when they are not scheduled as in-kind megawatt distributions through the original transaction or through a separately Tagged transaction.
11. POR and POD profiles — schedule of energy flow imported at the Point of Receipt and Exported at the Point of Delivery.
12. Transmission reservation number — reference to a particular transmission reservation being used to provide transmission capacity to support the transaction being described.
13. Transmission reservation profile — information describing the transmission reservation commitment.
14. Transmission product — the firmness of service associated with the transmission reservation being used.
15. Load — the physical characteristics of the energy sink.
16. Resource service point (sink) — the physical point at which the energy is being consumed. This may vary in granularity, dependent on local practices.
17. Energy profile — energy to be consumed by the Load for this Transaction.
18. Contact information of person representing the Purchasing-Selling Entity responsible for the Tag.

The following information is required to modify a Transaction:

19. The Transaction being curtailed or reloaded.
20. All necessary profile changes to set the maximum flow allowed for the transaction during the appropriate hours.
21. A contact person that initiated the curtailment or reload.

A. Introduction

1. **Title:** **Interchange Transaction Tag Communication and Reliability Assessment**

2. **Number:** INT-002-0

3. **Purpose:**

   To ensure that Interchange Transaction information is provided to all entities needing to make reliability assessments and to ensure all affected reliability entities assess the reliability impacts of Interchange Transactions before approving or denying a Tag. To communicate the approvals and denials of the Tag and the final composite status of the Tag.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Transmission Service Providers

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Sink Balancing Authority shall ensure that all Tags and any modifications to Tags are provided via a secure network to the following entities on the Scheduling Path:

R1.1. Sink and Source Balancing Authority for the Transaction.

R1.2. Intermediate Balancing Authorities on the Schedule Path.

R1.3. Transmission Service Provider(s) on the Schedule Path.

R1.4. Reliability analysis services (IDC or other regional reliability tools).

R1.5. Transmission Operators and Reliability Coordinators who may receive the information through Reliability analysis services.

R2. Transmission Service Providers on the Scheduling Path shall be responsible for assessing and approving or denying the Interchange Transaction based on established reliability criteria and adequacy of Interconnected Operating Services and transmission rights as well as the reasonableness of the Interchange Transaction Tag. The Transmission Service Provider shall verify and assess:

R2.1. Valid OASIS reservation number or transmission contract identifier.

R2.2. Transmission priority matches reservation.

R2.3. Energy profile fits within OASIS reservation.

R2.4. OASIS reservation accommodates all Interchange Transactions.

R2.5. Connectivity of adjacent Transmission Service Providers.

R2.6. Loss accounting.

R3. Balancing Authorities on the Scheduling Path shall be responsible for assessing and approving or denying the Interchange Transaction. The Balancing Authority shall verify and assess:

R3.1. Transaction start and end time.

R3.2. Energy profile (ability to support the magnitude of the transaction).

R3.3. Ramp (ability of generation maneuverability to accommodate).

R3.4. Scheduling path (proper connectivity of adjacent Balancing Authorities).

R4. Each Balancing Authority and Transmission Service Provider on the Scheduling Path shall communicate their approval or denial of the Interchange Transaction to the Sink Balancing Authority.

R5. Upon receipt of approvals or denials from all of the individual Balancing Authorities and Transmission Service Providers, the Sink Balancing Authority shall communicate the composite approval status of the Interchange Transaction to the Purchasing-Selling Entity and all other Balancing Authorities and Transmission Service Providers on the Scheduling Path and through the Reliability analysis service to affected Transmission Operators and Reliability Coordinators.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

1. MISO Scheduling Agent Waiver dated November 21, 2002.
2. MISO Enhanced Scheduling Agent Waiver dated July 16, 2003.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Proposed Effective Date	Errata

A. Introduction

1. **Title:** **Interchange Transaction Implementation**

2. **Number:** INT-003-0

3. **Purpose:**

   To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations. To ensure Balancing Authorities incorporate all confirmed Schedules into their ACE equations.

4. **Applicability**

   4.1. Balancing Authorities.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on:

R1.1.1. Interchange Schedule start and end time.

R1.1.2. Energy profile.

R1.1.3. Ramp start time and duration (Balancing Authorities shall use the Ramp duration established for their Interconnection unless they agree to an alternative Ramp duration.) Default Ramps durations are as follows:

- Default Ramp duration for the Eastern Interconnection shall be 10 minutes equally across the Interchange Schedule start and end times.
- Default Ramp duration for the Western Interconnection shall be 20 minutes equally across the Interchange Schedule start and end times.
- Ramp durations for Interchange Schedules implemented for compliance with NERC's Disturbance Control Standard (recovery from a disturbance condition) and Interchange Transaction curtailment in response to line loading relief procedures may be shorter than the above defaults, but must be identical for the Sending Balancing Authority and Receiving Balancing Authority.

R1.2. If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie.

R1.3. Balancing Authorities that implement Interchange Schedules that cross an Interconnection boundary shall use the same start time and Ramp durations.

R2. Balancing Authorities shall implement Interchange Schedules only with Adjacent Balancing Authorities.

R3. Balancing Authorities shall begin and end Interchange Schedules at a time agreed to by the Source Balancing Authority, Sink Balancing Authority, and Intermediate Balancing Authorities.

R4. The Sink Balancing Authority shall be responsible for initiating implementation of each Interchange Transaction as tagged. Upon receiving composite approval from the Sink

Balancing Authority, each Balancing Authority on the scheduling path shall enter confirmed Schedules into its Automatic Generation Control ACE equation.

R5. Balancing Authorities shall operate such that Interchange Schedules do not knowingly cause any other systems to violate established operating criteria.

R6. Balancing Authorities shall operate such that the maximum Net Interchange Schedule between any two Balancing Authorities does not exceed the lesser of:

R6.1. The total capacity of both the owned and arranged-for transmission facilities in service for any Transmission Service Provider along the path, or

R6.2. The established network Total Transfer Capability between Balancing Authorities, which considers other transmission facilities available to them under specific arrangements, and the overall physical constraints of the transmission network.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

1. MISO Scheduling Agent Waiver dated November 21, 2002.
2. MISO Enhanced Scheduling Agent Waiver dated July 16, 2003.
3. MISO Energy Flow Information Waiver dated July 16, 2003.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Interchange Transaction Modifications**

2. **Number:** INT-004-0

3. **Purpose:** To allow modifications to Interchange Transactions to address potential or actual System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations or other reliability conditions. To ensure Dynamic Transfers are adequately tagged to be able to determine their reliability impacts.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Reliability Coordinators

   4.3. Transmission Operators

   4.4. Purchasing-Selling Entities

5. **Effective Date:** April 1, 2005

B. Requirements

R1. If a Reliability Coordinator, Transmission Operator, or Source or Sink Balancing Authority, due to a reliability event, needs to modify an Interchange Transaction that is in progress or scheduled to be started, the entity shall, within 60 minutes of the start of the emergency Transaction, modify the Interchange Transaction tag, and shall communicate the modification to the Sink Balancing Authority. Reliability events may include:

R1.1. Transmission Loading Relief procedure curtailment — Eastern Interconnection.

R1.2. Interconnection, regional, or local overload relief or congestion management procedures.

R1.3. SOL or IROL potential or actual limit violation.

R1.4. Loss of generation.

R1.5. Loss of Load.

R2. A Generator Operator or Load Serving Entity may request the Host Balancing Authority to modify an Interchange Transaction due to loss of generation or Load.

R2.1. When a loss of generation necessitates curtailing Interchange Transactions, the Source Balancing Authority shall coordinate the modifications to the appropriate tags.

R2.2. When a loss of Load necessitates curtailing Interchange Transactions, the Sink Balancing Authority shall coordinate the modifications to the appropriate tags.

R3. Upon receipt of modification to an Interchange Transaction as described in Requirement R1, the Sink Balancing Authority (Source Balancing Authority in the case of a loss of generation) shall communicate the modified information about the Interchange Transaction, including its composite approval status, to all Balancing Authorities and Transmission Service Providers on the Transaction path and the Purchasing-Selling Entity responsible for the Transaction.

R4. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.

R5. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occur:

R5.1. The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±10%.

R5.2. The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±25 megawatt-hours.

R5.3. A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.

C. Measures

M1. The Sink Balancing Authority shall provide evidence that the responsible Purchasing-Selling Entity revised a tag when the deviation exceeded the criteria in Requirement R5.

D. Compliance

1. Compliance Monitoring Process

Periodic tag audit as prescribed by NERC. For the requested time period, the Sink Balancing Authority shall provide the instances when Dynamic Schedule deviation exceeded the criteria in Requirement 5 and shall provide evidence that the responsible Purchasing-Selling Entity submitted a revised tag.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

Three months.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Not specified.

2.2. Level 2: Not specified.

2.3. Level 3: Not specified.

2.4. Level 4: Not specified.

E. Regional Differences

1. WECC Tagging Dynamic Schedules and Inadvertent Payback Waiver dated November 21, 2002.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
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Attachment 1-INT-004-0

Interchange Transaction Modifications

Curtailments, reloads, market-initiated modifications, and other Transaction modifications that affect energy profiles must be received by and evaluated within certain times. The following tables describe the submission and evaluation requirements for such changes.

Modification requests received by the deadlines specified below shall be considered "on time," and are eligible for passive approval. Modification requests received past the deadlines shall be considered "late," and are considered denied unless explicitly approved by all parties.

Table 1: Eastern Interconnection — Modifications

Modification Type	**Requestor Submission Deadline*** **	**Actual Submission Time*****	**Evaluation Time**
Reliability (Curtailments or Reloads)	20 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
Market — Committed transmission reservation(s) Reductions	N/A	N/A	N/A
Market — Committed transmission reservation(s) Increases, Energy Reductions, Energy Increases*	20 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
***Start time references are for start of the Transaction not the start of the Ramp.			

Table 2: Western Interconnection — Modifications

Modification Type	**Requestor Submission Deadline*** **	**Actual Submission Time*****	**Evaluation Time**
Reliability (Curtailments or Reloads)	25 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
Market — Committed transmission reservation(s) Reductions	N/A	N/A	N/A

Market — Committed transmission reservation(s) Increases, Energy Reductions, Energy Increases*	25 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
***Start time references are for start of the Transaction not the start of the Ramp.			

*See Special Exception for Cancellations below.
**If received after deadline, requires active approval or will be passively denied

Special Exception for Cancellations

A cancellation is defined as setting both committed transmission reservation(s) and energy flow to zero for the duration of the Transaction prior to the start of a Transaction but following that Transaction's approval. In the event that a Purchasing-Selling Entity submitting the tag elects to cancel a Transaction, the following timelines should be utilized:

Table 3: Special Exception for Cancellations Submission and Evaluation Timing

Region	Submission Deadline*	Evaluation Time
Eastern Interconnection	15 minutes prior to transaction start	If received by deadline, no evaluation required. Request is automatically approved.
		If not received by deadline, request is not eligible for special exception for cancellations, and must be processed normally.
Western Interconnection	20 minutes prior to transaction start	If received by deadline, no evaluation required. Request is automatically approved.
		If not by deadline, request is not eligible for special exception for cancellations, and must be processed normally.
*Start time references are for start of the Transaction not the start of the Ramp.		

A. Introduction

1. **Title:** **Reliability Coordination – Responsibilities and Authorities**

2. **Number:** IRO-001-0

3. **Purpose:** Reliability Coordinators must have the authority, plans, and agreements in place to immediately direct reliability entities within their Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state. If a Reliability Coordinator delegates tasks to others, the Reliability Coordinator retains its responsibilities for complying with NERC and regional standards. Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market participant over another.

4. **Applicability**

   4.1. Reliability Coordinators.

   4.2. Regional Reliability Organizations.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.

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

R3. The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.

R4. Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.

R5. The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.

R6. The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.

R7. The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit or Interconnection Reliability Operating Limit violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.

R8. Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or

Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.

R9. The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.

C. Measures

M1. Documentation must clearly show that the Reliability Coordinator has the authority to immediately direct entities listed in Requirement R8 within its Reliability Coordinator Area to re-dispatch generation, reconfigure transmission, manage interchange transactions, or reduce system demand to mitigate SOL and IROL violations to return the system to a reliable state.

D. Compliance

1. Compliance Monitoring Process

The Regional Reliability Organization shall review the Reliability Coordinator documentation and the agreements with entities listed in Requirement R8 that delineate the authority of the Reliability Coordinator to immediately direct actions of these entities in its Reliability Coordinator Area to mitigate SOL and IROL violations to return the system to a reliable state.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One year without a violation from the time of the violation.

1.3. Data Retention

Documentation must be available at all times.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: N/A.

2.3. Level 3: Reliability Coordinator does not have documentation demonstrating authority to direct all the entities listed in Requirement R8 within its Reliability Coordinator Area to take actions to mitigate SOL and IROL violations to return the system to a reliable state.

2.4. Level 4: The Reliability Coordinator does not have the authority to direct all the entities listed in Requirement R8 in its Reliability Coordinator Area to take actions to mitigate SOL and IROL violations to return the system to a reliable state.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Reliability Coordination – Facilities**
2. **Number:** IRO 002-0
3. **Purpose:** Reliability Coordinators need information, tools and other capabilities to perform their responsibilities.
4. **Applicability**
   4.1. Reliability Coordinators.
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.

R2. Each Reliability Coordinator shall determine the data requirements to support its reliability coordination tasks and shall request such data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities, or adjacent Reliability Coordinators.

R3. Each Reliability Coordinator – or its Transmission Operators and Balancing Authorities – shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.

R4. Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.

R5. Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.

R6. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.

R7. Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.

R8. Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.

R9. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Reliability Coordination – Wide-Area View**

2. **Number:** IRO-003-1

3. **Purpose:** The Reliability Coordinator must have a wide area view of its own Reliability Coordinator Area and that of neighboring Reliability Coordinators.

4. **Applicability**

   4.1. Reliability Coordinators.

5. **Effective Date:** August 1, 2006

B. Requirements

R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.

R2. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Reliability Coordination — Operations Planning**

2. **Number:** IRO-004-1

3. **Purpose:** Each Reliability Coordinator must conduct next-day reliability analyses for its Reliability Coordinator Area to ensure the Bulk Electric System can be operated reliably in anticipated normal and Contingency conditions. System studies must be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. Plans must be developed to alleviate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations.

4. **Applicability**

   4.1. Reliability Coordinators.

   4.2. Balancing Authorities.

   4.3. Transmission Operators.

   4.4. Transmission Service Providers.

   4.5. Transmission Owners.

   4.6. Generator Owners.

   4.7. Generator Operators.

   4.8. Load-Serving Entities.

5. **Effective Date:** November 1, 2006

B. Requirements

R1. Each Reliability Coordinator shall conduct next-day reliability analyses for its Reliability Coordinator Area to ensure that the Bulk Electric System can be operated reliably in anticipated normal and Contingency event conditions. The Reliability Coordinator shall conduct Contingency analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.

R2. Each Reliability Coordinator shall pay particular attention to parallel flows to ensure one Reliability Coordinator Area does not place an unacceptable or undue Burden on an adjacent Reliability Coordinator Area.

R3. Each Reliability Coordinator shall, in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs.

R4. Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity in the Reliability Coordinator Area shall provide information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions. This information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R5. Each Reliability Coordinator shall share the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with Transmission Operators, Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area. The Reliability Coordinator shall make study results available no later than 1500 Central Standard Time for the Eastern Interconnection and 1500 Pacific Standard Time for the Western Interconnection, unless circumstances warrant otherwise.

R6. If the results of these studies indicate potential SOL or IROL violations, the Reliability Coordinator shall direct its Transmission Operators, Balancing Authorities and Transmission Service Providers to take any necessary action the Reliability Coordinator deems appropriate to address the potential SOL or IROL violation.

R7. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.

C. Measures

M1. Evidence that the Reliability Coordinator conducted next-day contingency analyses for its Reliability Coordinator Area to ensure that the Bulk Electric System could be operated reliably in anticipated normal and Contingency conditions.

D. Compliance

1. Compliance Monitoring Process

Entities will be selected for an on-site audit at least every three years. For a selected 30-day period in the previous three calendar months prior to the on site audit, Reliability Coordinators will be asked to provide documentation showing that next-day reliability analyses were conducted each day to ensure the bulk power system could be operated in anticipated normal and Contingency conditions; and that they identified potential interface and other operating limits including overloaded transmission lines and transformers, voltage and stability limits, etc.

1.1. Compliance Monitoring Responsibility

Self-Certification: Each Reliability Coordinator must annually self-certify compliance to its Regional Reliability Organization with the completion of the studies and action plans in Requirements R1, R2 and R3.

Exception Reporting: Reliability Coordinators will prepare a monthly report to the Regional Reliability Organization for each month that system studies were not conducted, indicating the dates that studies were not done and the reason why.

1.2. Compliance Monitoring Period and Reset Time Frame

One year without a violation from the time of the violation.

1.3. Data Retention

Documentation shall be available for 3 months to provide verification that system studies were performed as required.

1.4. Additional Compliance Information

None identified.

2. Levels of Non-Compliance

2.1. Level 1: System studies were not conducted for one day in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.

2.2. Level 2: System studies were not conducted for 2–3 days in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.

2.3. Level 3: System studies were not conducted for 4–5 days in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.

2.4. Level 4: System studies were not conducted for more than 5 days in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. Title: **Reliability Coordination — Current Day Operations**

2. Number: IRO-005-1

3. Purpose: The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.

4. Applicability

4.1. Reliability Coordinators.

4.2. Balancing Authorities.

4.3. Transmission Operators.

4.4. Transmission Service Providers.

5. Effective Date: November 1, 2006

B. Requirements

R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:

R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.

R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.4. System real and reactive reserves (actual versus required).

R1.5. Capacity and energy adequacy conditions.

R1.6. Current ACE for all its Balancing Authorities.

R1.7. Current local or Transmission Loading Relief procedures in effect.

R1.8. Planned generation dispatches.

R1.9. Planned transmission or generation outages.

R1.10. Contingency events.

R2. Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.

R3. As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability

Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.

R4. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.

R5. Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.

R6. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

R7. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.

R8. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

R9. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.

R10. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.

R11. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

R12. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

R13. Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and

Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

R14. Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

R15. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

R16. Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.

R17. When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Reliability Coordination — Transmission Loading Relief**

2. **Number:** IRO-006-1

3. **Purpose:** Regardless of the process it uses, the Reliability Coordinator must direct its Balancing Authorities and Transmission Operators to return the transmission system to within its Interconnection Reliability Operating Limits as soon as possible, but no longer than 30 minutes. The Reliability Coordinator needs to direct Balancing Authorities and Transmission Operators to execute actions such as reconfiguration, redispatch, or load shedding until relief requested by the TLR process is achieved.

4. **Applicability**

   4.1. Reliability Coordinators.

   4.2. Transmission Operators.

   4.3. Balancing Authorities.

5. **Effective Date:** August 8, 2005

B. Requirements

R1. A Reliability Coordinator shall take appropriate actions in accordance with established policies, procedures, authority, and expectations to relieve transmission loading.

R2. A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, at its discretion, select from either a "local" (Regional, Interregional, or subregional) transmission loading relief procedure or an Interconnection-wide procedure.

R2.1. The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection is provided in Attachment 1-IRO-006-0.

R2.2. The equivalent Interconnection-wide transmission loading relief procedure for use in the Western Interconnection is the "WSCC Unscheduled Flow Mitigation Plan," provided at: http://www.wecc.biz/documents/library/UFAS/UFAS_mitigation_plan_rev_2001-clean_8-8-03.pdf.

R2.3. The Interconnection-wide transmission loading relief procedure for use in ERCOT is provided as Section 7 of the ERCOT Protocols, posted at: http://www.ercot.com/tac/retailisoadhoccommittee/protocols/keydocs/draftercotprotocols.htm.

R3. The Reliability Coordinator may use local transmission loading relief or congestion management procedures, provided the Transmission Operator experiencing the potential or actual SOL or IROL violation is a party to those procedures.

R4. A Reliability Coordinator may implement a local transmission loading relief or congestion management procedure simultaneously with an Interconnection-wide procedure. However, the Reliability Coordinator shall follow the curtailments as directed by the Interconnection-wide procedure. A Reliability Coordinator desiring to use a local procedure as a substitute for curtailments as directed by the Interconnection-wide procedure shall have such use approved by the NERC Operating Committee.

R5. When implemented, all Reliability Coordinators shall comply with the provisions of the Interconnection-wide procedure including, for example, action by Reliability Coordinators in other Interconnections to curtail an Interchange Transaction that crosses an Interconnection boundary.

R6. During the implementation of relief procedures, and up to the point that emergency action is necessary, Reliability Coordinators and Balancing Authorities shall comply with interchange scheduling standards INT-001 through INT-004.

C. Measures

M1. If required, an investigation will be conducted to determine whether appropriate actions were taken in accordance with established policies, procedures, authority, and expectations to relieve transmission loading, including notifying appropriate Reliability Coordinators and operating entities to curtail Interchange Transactions.

D. Compliance

1. Compliance Monitoring Process

The Regional Reliability Organization or NERC may initiate an investigation if there is a complaint that an entity has not implemented relief procedures in accordance with these requirements.

1.1. Compliance Monitoring Responsibility

Not specified.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance Monitoring Period: One calendar year.

Reset Period: One month without a violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: The Reliability Coordinator did not implement loading relief procedures in accordance with the standard.

E. Regional Differences

PJM/MISO Enhanced Congestion Management (Curtailment/Reload/Reallocation) Waiver approved March 25, 2004.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 8, 2005	Revised Attachment 1	Revision

Attachment 1-IRO-006-1

Transmission Loading Relief Procedure — Eastern Interconnection

Purpose

This standard defines procedures for curtailment and reloading of Interchange Transactions to relieve overloads on transmission facilities modeled in the Interchange Distribution Calculator. This process is defined in the requirements below, and is depicted in Appendix A. Examples of curtailment calculations using these procedures are contained in Appendix B.

Applicability

This standard only applies to the Eastern Interconnection.

1. Transmission Loading Relief (TLR) Procedure

1.1. Initiation only by Reliability Coordinator. A Reliability Coordinator shall be the only entity authorized to initiate the TLR Procedure and shall do so at 1) the Reliability Coordinator's own request, or 2) upon the request of a Transmission Operator.

1.2. Mitigating transmission constraints. A Reliability Coordinator may utilize the TLR Procedure to mitigate potential or actual System Operating Limit (SOL) violations or Interconnection Reliability Operating Limit (IROL) violations on any transmission facility modeled in the IDC.

1.2.1. Requesting relief on tie facilities. Any Transmission Operator who operates the tie facility shall be allowed to request relief from its Reliability Coordinator.

1.2.1.1. Interchange Transaction priority on tie facilities. The priority of the Interchange Transaction(s) to be curtailed shall be determined by the Transmission Service reserved on the Transmission Service Provider's system who requested the relief.

1.3. Order of TLR Levels and taking emergency action. The Reliability Coordinator shall not be required to follow the TLR Levels in their numerical order (Section 2, "TLR Levels"). Furthermore, if a Reliability Coordinator deems that a transmission loading condition could jeopardize Bulk Electric System reliability, the Reliability Coordinator shall have the authority to enter TLR Level 6 directly, and immediately direct the Balancing Authorities or Transmission Operators to take such actions as redispatching generation, or reconfiguring transmission, or reducing load to mitigate the critical condition until Interchange Transactions can be reduced utilizing the TLR Procedure or other methods to return the system to a secure state.

1.4. Notification of TLR Procedure implementation. The Reliability Coordinator initiating the use of the TLR Procedure shall notify other Reliability Coordinators and Balancing Authorities and Transmission Operators, and must post the initiation and progress of the TLR event on the appropriate NERC web page(s).

1.4.1. Notifying other Reliability Coordinators. The Reliability Coordinator initiating the TLR Procedure shall inform all other Reliability Coordinators via the Reliability Coordinator Information System (RCIS) that the TLR Procedure has been implemented.

1.4.1.1. **Actions expected.** The Reliability Coordinator initiating the TLR Procedure shall indicate the actions expected to be taken by other Reliability Coordinators.

1.4.2. **Notifying Transmission Operators and Balancing Authorities.** The Reliability Coordinator shall notify Transmission Operators and Balancing Authorities in its Reliability Area when entering and leaving any TLR level.

1.4.3. **Notifying Balancing Authorities.** The Reliability Coordinator for the sink Balancing Authority shall be responsible for directing the Sink Balancing Authority to curtail the Interchange Transactions as specified by the Reliability Coordinator implementing the TLR Procedure.

1.4.3.1. **Notification order**. Within a Transmission Service Priority level, the Sink Balancing Authorities whose Interchange Transactions have the largest impact on the Constrained Facilities shall be notified first if practicable.

1.4.4. **Updates**. At least once each hour, or when conditions change, the Reliability Coordinator implementing the TLR Procedure shall update all other Reliability Coordinators (via the RCIS). Transmission Operators and Balancing Authorities who have had Interchange Transactions impacted by the TLR will be updated by their Reliability Coordinator.

1.5. **Obligations**. All Reliability Coordinators shall comply with the request of the Reliability Coordinator who initiated the TLR Procedure, unless the initiating Reliability Coordinator agrees otherwise.

1.5.1. **Use of TLR Procedure with "local" procedures**. A Reliability Coordinator shall be allowed to implement a local transmission loading relief or congestion management procedure simultaneously with an Interconnection-wide procedure. However, the Reliability Coordinator shall be obligated to follow the curtailments as directed by the Interconnection-wide procedure. If the Reliability Coordinator desires to use a local procedure as a substitute for Curtailments as directed by the Interconnection-wide procedure, it may do so only if such use is approved by the NERC Operating Committee.

1.6. **Consideration of Interchange Transactions.** The administration of the TLR Procedure shall be guided by information obtained from the IDC.

1.6.1. **Interchange Transactions not in the IDC.** Reliability Coordinators shall also treat known Interchange Transactions that may not appear in the IDC in accordance with the procedures in this document.

1.6.2. **Transmission elements not in IDC.** When a Reliability Coordinator is faced with an overload on a transmission element that is not modeled in the IDC, the Reliability Coordinator shall use the best information available to curtail Interchange Transactions in order to operate the system in a reliable manner. The Reliability Coordinator shall use its best efforts to ensure that Interchange Transactions with a Transfer Distribution Factor of less than the Curtailment Threshold on the transmission element not modeled in the IDC are not curtailed.

1.6.3. **Questionable IDC results.** Any Reliability Coordinator (or Transmission Operator through its Reliability Coordinator) who believes the curtailment list from the IDC for a particular TLR event is incorrect shall use its best efforts to communicate those adjustments necessary to bring the curtailment list into conformance with the principles of this Procedure to the initiating Reliability Coordinator. Causes of questionable IDC results may include:

- Missing Interchange Transactions that are known to contribute to the Constraint.
- Significant change in transmission system topology.
- TDF matrix error.

Impacts of questionable IDC results may include:

- Curtailment that would have no effect on, or aggravate the constraint.
- Curtailment that would initiate a constraint elsewhere.

If other Reliability Coordinators are involved in the TLR event, all impacted Reliability Coordinators shall be in agreement before any adjustments to the Curtailment list are made.

1.6.4. **Curtailment that would cause a constraint elsewhere.** A Reliability Coordinator shall be allowed to exempt an Interchange Transaction from Curtailment if that Reliability Coordinator is aware that the Interchange Transaction Curtailment directed by the IDC would cause a constraint to occur elsewhere. This exemption shall only be allowed after the Reliability Coordinator has consulted with the Reliability Coordinator who initiated the Curtailment.

1.6.5. **Redispatch options.** The Reliability Coordinator shall ensure that Interchange Transactions that are linked to redispatch options are protected from Curtailment in accordance with the redispatch provisions.

1.6.6. **Reallocation.** The Reliability Coordinator shall consider for Reallocation any Transactions of higher priority that meet the approved tag submission deadline during a TLR Level 3A. The Reliability Coordinator shall consider for Reallocation any Transaction using Firm Transmission Service that has met the approved tag submission deadline during a TLR Level 5A. Note Reallocations for Dynamic Schedules are as follows: If an Interchange Transaction is identified as a Dynamic Schedule and the transmission service is considered firm according to the constrained path method, then it will not be held by the IDC during TLR level 4 or lower. Adjustments to Dynamic Schedules in accordance with INT-004 R5 will not be held under TLR level 4 or lower.

1.7 **IDC updates.** Any Interchange Transaction adjustments or curtailments that result from using this Procedure must be entered into the IDC.

1.8 **Logging.** The Reliability Coordinator shall complete the NERC Transmission Loading Relief Procedure Log whenever it invokes TLR Level 2 or above, and send a copy of the log via email to NERC within two business days of the TLR event for posting on the NERC website.

1.9 **TLR Event Review.** The Reliability Coordinator shall report the TLR event to the NERC Market Committee and Operating Reliability Subcommittee in accordance with TLR review processes established by NERC as required.

1.9.1. **Providing information**. Transmission Operators and Balancing Authorities within the Reliability Coordinator's Area, and all other Reliability Coordinators, including Transmission Operators and Balancing Authorities within their respective Reliability Areas, shall provide information, as requested by the initiating Reliability Coordinator, in accordance with TLR review processes established by NERC.

1.9.2. **Market Committee reviews.** The Market Committee may conduct reviews of certain TLR events based on the size and number of Interchange Transactions that are affected, the frequency that the TLR Procedure is called for a particular Constrained Facility, or other factors.

1.9.3. **Operating Reliability Subcommittee reviews.** The Operating Reliability Subcommittee shall conduct reviews to ensure proper implementation and for "lessons learned."

2. Transmission Loading Relief (TLR) Levels

Introduction

This section describes the various levels of the TLR Procedure. The description of each level begins with the circumstances that define the TLR Level, followed by the procedures to be followed.

The decision that a Reliability Coordinator makes in selecting a particular TLR Level often depends on the transmission loading condition and whether the Interchange Transaction is using Non-firm Point-to-Point Transmission Service or Firm Point-to-Point Transmission Service. There are further considerations that depend on whether the Constrained Facility is on or off the Contract Path. It is important to note that an Interchange Transaction using Firm Point-to-Point Transmission Service on all Contract Path links is considered a "firm" Interchange Transaction even if the Constrained Facility is off the Contract Path.

2.1. TLR Level 1 — Notify Reliability Coordinators of potential SOL or IROL Violations

2.1.1. The Reliability Coordinator shall use the following circumstances to establish the need for TLR Level 1**:**

- The transmission system is secure.
- The Reliability Coordinator foresees a transmission or generation contingency or other operating problem within its Reliability Area that could cause one or more transmission facilities to approach or exceed their SOL or IROL.

2.1.2. Notification procedures. The Reliability Coordinator shall notify all Reliability Coordinators via the Reliability Coordinator Information System (RCIS) as soon as the condition is foreseen. All affected Reliability Coordinators shall check to ensure that Interchange Transactions are posted in the IDC.

2.2. TLR Level 2 — Hold transfers at present level to prevent SOL or IROL Violations

2.2.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 2:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.

2.2.2. Holding procedures. The Reliability Coordinator shall be allowed to hold the implementation of any additional Interchange Transactions that are at or above the Curtailment Threshold. However, the Reliability Coordinator should allow additional Interchange Transactions that flow across the Constrained Facility if their flow reduces the loading on the Constrained Facility or has a Transfer Distribution Factor less than the Curtailment Threshold. All Interchange Transactions using Firm Point-to-Point Transmission Service shall be allowed to start.

2.2.3. TLR Level 2 is a transient state, which requires a quick decision to proceed to higher TLR Levels (3 and above) to allow Interchange Transactions to be implemented according to their transmission reservation priority. The time for being in TLR Level 2 should be no more than 30 minutes, with the understanding that there may be circumstances where this time may be exceeded. If the time in TLR Level 2 exceeds 30 minutes, the Reliability Coordinator shall document this action on the TLR Log.

2.3. TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service

2.3.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3a:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.
- The Transmission Provider has previously approved a higher priority Point-to-Point Transmission Service reservation over which a Transmission Customer wishes to begin an Interchange Transaction.

2.3.2. Reallocation procedures to allow Interchange Transactions using higher priority Point-to-Point Transmission Service to start. The Reliability Coordinator with the constraint shall give preference to those Interchange Transactions using Firm Point-to-Point Transmission Service, followed by those using higher priority Non-firm Point-to-Point Transmission Service as specified in Section 3. "Interchange Transaction Curtailment Order." Interchange Transactions that have been held or curtailed as prescribed in this Section shall be reallocated (reloaded) according to their Transmission Service priorities when operating conditions permit as specified in Section 6. "Interchange Transaction Reallocation During TLR Level 3a and 5a."

2.3.2.1. The Reliability Coordinator shall displace Interchange Transactions with lower priority Transmission Service using Interchange Transactions having higher priority Non-firm or Firm Transmission Service.

2.3.2.2. The Reliability Coordinator shall not curtail Interchange Transactions using Non-firm Transmission Service to allow the start or increase of another Interchange Transaction having the same priority Non-firm Transmission Service.

2.3.2.3. If there are insufficient Interchange Transactions using Non-firm Point-to-Point Transmission Service that can be curtailed to allow for Interchange Transactions using Firm Point-to-Point Transmission Service to begin, the Reliability Coordinator shall proceed to TLR Level 5a.

2.3.2.4. The Reliability Coordinator shall reload curtailed Interchange Transactions prior to allowing the start of new or increased Interchange Transactions.

2.3.2.4.1. Interchange Transactions whose tags were submitted prior to the TLR Level 2 or Level 3a being called, but were subsequently held from starting, are considered to have been curtailed and thus would be reloaded the same time as the curtailed Interchange Transactions.

2.3.2.5. The Reliability Coordinator shall fill available transmission capability by reloading or starting eligible Transactions on a pro-rata basis.

2.3.2.6. The Reliability Coordinator shall consider transactions whose tags meet the approved tag submission deadline for Reallocation for the upcoming hour. Tags submitted after this deadline shall be considered for Reallocation the following hour.

2.4. TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation

2.4.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3b**:**

- One or more transmission facilities are operating above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.

2.4.2. Holding new Interchange Transactions. The Reliability Coordinator shall hold all new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold during the period of the SOL or IROL Violation. The Reliability Coordinator shall allow Interchange Transactions using Firm Point-to-Point Transmission Service to start if they are submitted to the IDC within specific time limits as explained in Section 7. "Interchange Transaction Curtailments during TLR Level 3b."

2.4.3. Curtailment procedures to mitigate an SOL or IROL. The Reliability Coordinator shall curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold as specified in Section 3, "Interchange Transaction Curtailment Order.**"**

2.5. TLR Level 4 — Reconfigure Transmission

2.5.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 4**:**

- One or more Transmission Facilities are above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken.

2.5.2. Holding new Interchange Transactions. The Reliability Coordinator shall hold all new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold during the period of the SOL or IROL Violation. The Reliability Coordinator shall allow Interchange Transactions using Firm Point-to-Point Transmission Service to start if they are submitted to the IDC by 25 minutes past the hour or the time at which the TLR

Level 4 is called, whichever is later. See Appendix E, Section E2 – Timing Requirements.

2.5.3. Reconfiguration procedures. Following the curtailment of all Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold in Level 3b that impact the Constrained Facilities, if a SOL or IROL violation is imminent or occurring, the Reliability Coordinator(s) shall request that the affected Transmission Operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint. Specific details are explained in Section 4, "Principles for Mitigating Constraints On and Off the Contract Path".

2.6. TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service

2.6.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 5a**:**

- The transmission system is secure.
- One or more transmission facilities are at their SOL or IROL.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- The Transmission Provider has been requested to begin an Interchange Transaction using previously arranged Firm Transmission Service that would result in a SOL or IROL violation.
- No further transmission reconfiguration is possible or effective.

2.6.2. Reallocation procedures to allow new Interchange Transactions using Firm Point-to-Point Transmission Service to start. The Reliability Coordinator shall use the following three-step process for Reallocation of Interchange Transactions using Firm Point-to-Point Transmission Service:

2.6.2.1. Step 1 — Identify available redispatch options. The Reliability Coordinator shall assist the Transmission Operator(s) in identifying those known redispatch options that are available to the Transmission Customer that will mitigate the loading on the Constrained Facilities. If such redispatch options are deemed insufficient to mitigate loading on the Constrained Facilities, the Reliability Coordinator shall proceed to implement these options while proceeding to Steps 2 and 3 below.

2.6.2.2. Step 2 — The Reliability Coordinator shall calculate the percent of the overload on the Constrained Facility caused by both Firm Point-to-Point Transmission Service (at or above the Curtailment Threshold) and the Transmission Provider's Network Integration Transmission Service and Native Load, as required by the Transmission Provider's filed tariff. This is described in Section 5, "Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service."

2.6.2.3. Step 3 — Curtail Interchange Transactions using Firm Transmission Service. The Reliability Coordinator shall curtail or reallocate on a pro-rata basis (based on the MW level of the MW total to all such Interchange Transactions), those Interchange Transactions as calculated in Section 7.2.2 over the Constrained Facilities. (See also Section 6, “Interchange Transaction Reallocation during TLR 3a and 5a.”) The Reliability Coordinator shall assist the Transmission Provider in curtailing Transmission Service to Network Integration Transmission Service customers and Native Load if such curtailments are required by the Transmission Provider’s tariff. Available redispatch options will continue to be implemented.

2.7. TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation

2.7.1. The Reliability Coordinator shall use following circumstances to establish the need for entering TLR Level 5b**:**

- One or more Transmission Facilities are operating above their SOL or IROL, or
- Such operation is imminent, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- No further transmission reconfiguration is possible or effective.

2.7.2. The Reliability Coordinator shall use the following three-step process for curtailment of Interchange Transactions using Firm Point-to-Point Transmission Service:

2.7.2.1. Step 1 — Identify available redispatch options. The Reliability Coordinator shall assist the Transmission Operator(s) in identifying those known redispatch options that are available to the Transmission Customer that will mitigate the loading on the Constrained Facilities. If such redispatch options are deemed insufficient to mitigate loading on the Constrained Facilities, the Reliability Coordinator shall proceed to implement these options while proceeding to Steps 2 and 3 below.

2.7.2.2. Step 2 — The Reliability Coordinator shall calculate the percent of the overload on the Constrained Facility caused by both Firm Point-to-Point Transmission Service (at or above the Curtailment Threshold) and the Transmission Provider’s Network Integration Transmission Service and Native Load, as required by the Transmission Provider’s filed tariff. This is described in Section 5, “Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service.”

2.7.2.3. Step 3 — Curtailment of Interchange Transactions using Firm Transmission Service. At this point, the Reliability Coordinator shall begin the process of curtailing Interchange Transactions as calculated in Section 2.7.2.2 over the Constrained Facilities using Firm Point-to-Point Transmission Service until the SOL or IROL violation has been mitigated. The Reliability Coordinator shall assist the Transmission Provider in curtailing Transmission Service to Network Integration Transmission Service customers and Native Load if such curtailments are required by the Transmission Providers' tariff. Available redispatch options will continue to be implemented.

2.8. TLR Level 6 — Emergency Procedures

2.8.1. The Reliability Coordinator shall use following circumstances to establish the need for entering TLR Level 6**:**

- One or more Transmission Facilities are above their SOL or IROL.
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.

2.8.2. **Implementing emergency procedures.** If the Reliability Coordinator deems that transmission loading is critical to Bulk Electric System reliability, the Reliability Coordinator shall immediately direct the Balancing Authorities and Transmission Operators in its Reliability Area to redispatch generation, or reconfigure transmission, or reduce load to mitigate the critical condition until Interchange Transactions can be reduced utilizing the TLR Procedures or other procedures to return the system to a secure state. All Balancing Authorities and Transmission Operators shall comply with all requests from their Reliability Coordinator.

2.9. TLR Level 0 — TLR concluded

2.9.1. **Interchange Transaction restoration and notification procedures.** The Reliability Coordinator initiating the TLR Procedure shall notify all Reliability Coordinators within the Interconnection via the RCIS when the SOL or IROL violations are mitigated and the system is in a reliable state, allowing Interchange Transactions to be reestablished at its discretion. Those with the highest transmission priorities shall be reestablished first if possible.

3. Interchange Transaction Curtailment Order for use in TLR Procedures

3.1. Priority of Interchange Transactions

3.1.1. Interchange Transaction curtailment priority shall be determined by the Transmission Service reserved over the constrained facility(ies) as follows:

Transmission Service Priorities

Priority 0. Next-hour Market Service — NX*

Priority 1. Service over secondary receipt and delivery points — NS

Priority 2. Non-Firm Point-to-Point Hourly Service — NH

Priority 3. Non-Firm Point-to-Point Daily Service — ND

Priority 4. Non-Firm Point-to-Point Weekly Service — NW

Priority 5. Non-Firm Point-to-Point Monthly Service — NM

Priority 6. Network Integration Transmission Service from sources not designated as network resources — NN

Priority 7. Firm Point-to-Point Transmission Service — F and Network Integration Transmission Service from Designated Resources — FN

3.1.2. The curtailment priority for Interchange Transactions that do not have a Transmission Service reservation over the constrained facility(ies) shall be defined by the lowest priority of the individual reserved transmission segments.

3.2. Curtailment of Interchange Transactions Using Non-firm Transmission Service

3.2.1. The Reliability Coordinator shall direct the curtailment of Interchange Transactions using Non-firm Transmission Service that are at or above the Curtailment Threshold for the following TLR Levels:

3.2.1.1. TLR Level 3a. Enable Interchange Transactions using a higher Transmission reservation priority to be implemented, or

3.2.1.2. TLR Level 3b. Mitigate an SOL or IROL violation.

3.3. Curtailment of Interchange Transactions Using Firm Transmission Service

3.3.1. The Reliability Coordinator shall direct the curtailment of Interchange Transactions using Firm Transmission Service that are at or above the Curtailment Threshold for the following TLR Levels:

3.3.1.1. TLR Level 5a. Enable additional Interchange Transactions using Firm Point-to-Point Transmission Service to be implemented after all Interchange Transactions using Non-firm Point-to-Point Service have been curtailed, or

3.3.1.2. TLR Level 5b. Mitigate a SOL or IROL violation that remains after all Interchange Transactions using Non-firm Transmission Service has been curtailed under TLR Level 3b, and following attempts to reconfigure transmission under TLR Level 4.

4. Mitigating Constraints On and Off the Contract Path during TLR

Introduction

Reserving Transmission Service for an Interchange Transaction along a Contract Path may not reflect the actual distribution of the power flows over the transmission network from generation source to load sink. Interchange Transactions arranged over a Contract Path may, therefore, overload transmission elements on other electrically parallel paths.

The curtailment priority of an Interchange Transaction depends on whether the Constrained Facility is on or off the Contract Path as detailed below.

4.1. Constraints ON the Contract Path

4.1.1. The Reliability Coordinator initiating TLR shall consider the entire Interchange Transaction non-firm if the transmission link (i.e., a segment on the Contract Path) on the Constrained Facility is Non-firm Point-to-Point Transmission Service, even if other links in the Contract Path are firm. When the Constrained Facility is on the Contract Path, the Interchange Transaction takes on the Transmission Service Priority of the Transmission Service link with the Constrained Facility regardless of the Transmission Service Priority on the other links along the Contract Path.

Discussion. The Transmission Operator simply has to call its Reliability Coordinator, request the TLR Procedure be initiated, and allow the curtailments of all Interchange Transactions that are at or above the Curtailment Threshold to progress until the relief is realized. Firm Point-to-Point Transmission Service links elsewhere in the Contract Path do not obligate Transmission Providers providing Non-firm Point-to-Point Transmission Service to treat the transaction as firm. For curtailment purposes, the Interchange Transaction's priority will be the priority of the Transmission Service link with the Constrained Facility. (See Requirement 4.1.2 below.)

4.1.2. The Reliability Coordinator initiating TLR shall consider the entire Interchange Transaction firm if the transmission link on the Constrained Facility is Firm Point-to-Point Transmission Service, even if other links in the Contract Path are non-firm.

Discussion. The curtailment priority of an Interchange Transaction on a Contract Path link is not affected by the Transmission Service Priorities arranged with other links on the Contract Path. If the Constrained Facility is on a Firm Point-to-Point Transmission Service Contract Path link, then the curtailment priority of the Interchange Transaction is considered firm regardless of the Transmission Service arrangements elsewhere on the Contract Path. If the Transmission Provider provides its services under the FERC pro forma tariff, it may also be obligated to offer its Transmission Customer alternate receipt and delivery points, thus allowing the customer to curtail its Transmission Service over the Constrained Facilities.

4.2. Constraints OFF the Contract Path

4.2.1. The Reliability Coordinator initiating TLR shall consider the entire Interchange Transaction non-firm if none of the transmission links on the Contract Path are on the Constrained Facility and if any of the transmission links on the Contract Path are Non-firm Point-to-Point Transmission Service; the Interchange

Transaction shall take on the lowest Transmission Service Priority of all Transmission Service links along the Contract Path.

Discussion. An Interchange Transaction arranged over a Contract Path where one or more individual links consist of Non-firm Point-to-Point Transmission Service is considered to be a non-firm Interchange Transaction for Constrained Facilities off the Contract Path. Sufficient Interchange Transactions that are at or above the Curtailment Threshold will be curtailed before any Interchange Transactions using Firm Point-to-Point Transmission Service are curtailed. The priority level for curtailment purposes will be the lowest level of Transmission Service arranged for on the Contract Path.

4.2.2. The Reliability Coordinator initiating TLR shall consider the entire Interchange Transaction firm if all of the transmission links on the Contract Path are Firm Point-to-Point Transmission Service, even if none of the transmission links are on the Constrained Facility and shall not be curtailed to relieve a Constraint off the Contract Path until all non-firm Interchange Transactions that are at or above the Curtailment Threshold have been curtailed.

Discussion. If the entire Contract Path is Firm Point-to-Point Transmission Service, then the TLR procedure will treat the Interchange Transaction as firm, even for Constraints off the Contract Path, and will not curtail that Interchange Transaction until all non-firm Interchange Transactions that are at or above the Curtailment Threshold have been curtailed. However, Transmission Providers off the Contract Path are not obligated to reconfigure their transmission system or provide other congestion management procedures unless special arrangements are in place. Because the Interchange Transaction is considered firm everywhere, the Reliability Coordinator may attempt to arrange for Transmission Operators to reconfigure transmission or provide other congestion management options or Balancing Authorities to redispatch, even if they are off the Contract Path, to try to avoid curtailing the Interchange Transaction that is using the Firm Point-to-Point Transmission Service.

5. Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service during TLR

Introduction

The provision of Point-to-Point Transmission Service, Network Integration Transmission Service and service to Native Load results in parallel flows on the transmission network of other Transmission Operators. When a transmission facility becomes constrained curtailment of Interchange Transactions is required to allow Interchange Transactions of higher priority to be scheduled (Reallocation) or to provide transmission loading relief (Curtailment). An Interchange Transaction is considered for Reallocation or Curtailment if its Transfer Distribution Factor (TDF) exceeds the TLR Curtailment Threshold.

In compliance with the Transmission Service Provider tariffs, Interchange Transactions using Non-firm Point-to-Point Transmission Service are curtailed first (TLR Level 3a and 3b), followed by transmission reconfiguration (TLR Level 4), and then the curtailment of Interchange Transactions using Firm Point-to-Point Transmission Service, Network Integration Transmission Service and service to Native Load (TLR Level 5a and 5b). Curtailment of Firm Point-to-Point Transmission Service shall be accompanied by the comparable curtailment of Network Integration Transmission Service and service to Native Load to the degree that these three Transmission Services contribute to the Constraint.

5.1. Requirements

A methodology, called the Per Generator Method without Counter Flow, or simply the Per Generator Method, has been programmed into the IDC to calculate the portion of parallel flows on any Constrained Facility due to service to Native Load of each Balancing Authority. The following requirements are necessary to assure comparable Reallocation or Curtailment of firm Transmission Service:

5.1.1. The Reliability Coordinator initiating a curtailment shall identify for curtailment all firm Transmission Services (i.e. Point-to-Point, Network Integration and service to Native Load) that contribute to the flow on any Constrained Facility by an amount greater than or equal to the Curtailment Threshold on a pro rata basis.

5.1.2. For Firm Point-to-Point Transmission Services, the Transfer Distribution Factors must be greater than or equal to the Curtailment Threshold.

5.1.3. For Network Integration Transmission Service and service to Native Load, the Generator-To-Load Distribution Factors must be greater than or equal to the Curtailment Threshold.

5.1.4. The Per Generator Method shall assign the amount of Constrained Facility relief that must be achieved by each Balancing Authority's Network Integration Transmission Service or service to Native Load. It shall not specify how the reduction will be achieved.

5.1.5. All Balancing Authorities in the Eastern Interconnection shall be obligated to achieve the amount of Constrained Facility relief assigned to them by the Per Generator Method.

5.1.6. The implementation of the Per Generator Method shall be based on transmission and generation information that is readily available.

5.2. Calculation Method

The calculation of the flow on a Constrained Facility due to Network Integration Transmission Service or service to Native Load shall be based on the Generation Shift Factors (GSFs) of a Balancing Authority's assigned generation and the Load Shift Factors (LSFs) of its native load, relative to the system swing bus. The GSFs shall be calculated from a single bus location in the IDC. The IDC shall report all generators assigned to native load for which the GLDF is greater than or equal to the Curtailment Threshold.

6. Interchange Transaction Reallocation During TLR Levels 3a and 5a

Introduction

This section provides the details for implementing TLR Levels 3a and 5a, both of which provide a means for Reallocation of Transmission Service.

TLR Level 3a accomplishes Reallocation by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Non-firm or Firm Point-to-Point Transmission Service to start. (See **Requirement 2.3, "TLR Level 3a.")** When a TLR Level 3a is in effect, Reliability Coordinators shall reallocate Interchange Transactions according to the Transactions' Transmission Service Priorities. Reallocation also includes the orderly reloading of Transactions by priority when conditions permit curtailed Transactions to be reinstated.

TLR Level 5a accomplishes Reallocation by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro-rata basis to allow new Interchange Transactions using Firm Point-to-Point Transmission Service to begin, also on a pro-rata basis. (See **Requirement 2.6, "TLR Level 5a.")**

6.1. Requirements

The basic requirements for Transaction Reallocation are as follows:

6.1.1. When identifying transactions for Reallocation the Reliability Coordinator shall normally only involve Curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service during TLR 3a. However, Reallocation may be used during TLR 5a to allow the implementation of additional Interchange Transactions using Firm Transmission Service on a pro-rata basis.

6.1.2. When identifying transactions for Reallocation, the Reliability Coordinator shall only consider those Interchange Transactions at or above the Curtailment Threshold for which a TLR 2 or higher is called.

6.1.3. When identifying transactions for Reallocation, the Reliability Coordinator shall displace Interchange Transactions utilizing lower priority Transmission Service with Interchange Transactions utilizing higher Transmission Service Priority.

6.1.4. When identifying transactions for Reallocation, the Reliability Coordinator shall not curtail Interchange Transactions using Non-firm Transmission Service to allow the start or increase of another transaction having the same Non-Firm Transmission Service Priority (marginal "bucket").

6.1.5. When identifying transactions for Reallocation, the Reliability Coordinator shall reload curtailed Interchange Transactions prior to starting new or increasing existing Interchange Transactions.

6.1.6. Interchange Transactions whose tags were submitted prior to the TLR 2 or 3a being called, but were subsequently held from starting because they failed to meet the approved tag submission deadline for Reallocation (see Section 6.2, "Communications and Timing Requirements"), shall be considered to have been curtailed and thus would be eligible for reload at the same time as the curtailed Interchange Transaction.

6.1.7. The Reliability Coordinator shall reload or start all eligible Transactions on a pro-rata basis.

6.1.8. Interchange Transactions whose tags meet the approved tag submission deadline for Reallocation (see Section 6.2, "Communications and Timing Requirements") shall be considered for Reallocation for the upcoming hour. (However, Interchange Transactions using Firm Point-to-Point Transmission Service shall be allowed to start as scheduled.) Interchange Transactions whose tags are submitted to the IDC after the approved tag submission deadline for Reallocation shall be considered for Reallocation the following hour. This applies to Interchange Transactions using either Non-firm Point-to-Point Transmission Service or Firm Point-to-Point Transmission Service. If an Interchange Transaction using Firm Interchange Transaction is submitted after the approved tag submission deadline and after the TLR is declared, that Transaction shall be held and then allowed to start in the upcoming hour.

It should be noted that calling a TLR 3a does not necessarily mean that Interchange Transactions using Non-firm Transmission Service will always be curtailed the next hour. However, TLR Levels 3a and 5a trigger the approved tag submission deadline for Reallocation requirements and allow for a coordinated assessment of all Interchange Transactions tagged to start the upcoming hour.

6.2. Communication and Timing Requirements

The following timeline shall be utilized to support Reallocation decisions during TLR Levels 3a or 5a. See Figures 2 and 3 for a depiction of the Reallocation Time Line.

6.2.1. **Time Convention**. In this document, the beginning of the current hour shall be referenced as 00:00. The beginning of the next hour shall be referenced as 01:00. The end of the next hour shall be referenced as 02:00. See Figure 1.

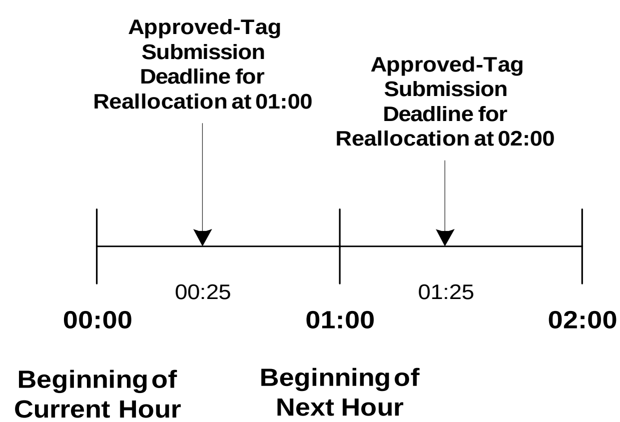


Figure 1 - Timeline showing Approved-tag Submission Deadline for Reallocation

6.2.2. **Approved tag submission deadline for Reallocation** Reliability Coordinators shall consider all approved Tags for Interchange Transactions at or above the Curtailment Threshold that have been submitted to the IDC by 00:25 for Reallocation at 01:00. See Figure 1. However, Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled.

6.2.2.1. Reliability Coordinators shall consider all approved tags submitted to the IDC beyond these deadlines for Reallocation at 02:00 (for both Firm and Non-firm Point-to-Point Transmission Service). However, these Interchange Transactions will not be allowed to start or increase at 01:00.

6.2.2.2. The approved tag submission deadline for Reallocation shall cease to be in effect as soon as the TLR level is reduced to 1 or 0.

6.2.3. Off-hour Transactions. Interchange Transactions with a start time other than *xx*:00 shall be considered for Reallocation at *xx*+1:00. For example, an Interchange Transaction with a start time of 01:05 and whose Tag was submitted at 00:15 will be considered for Reallocation at 02:00.

6.2.4. Tag Evaluation Period. Balancing Authorities and Transmission Providers shall evaluate all tags submitted for Reallocation and shall communicate approval or rejection by 00:25.

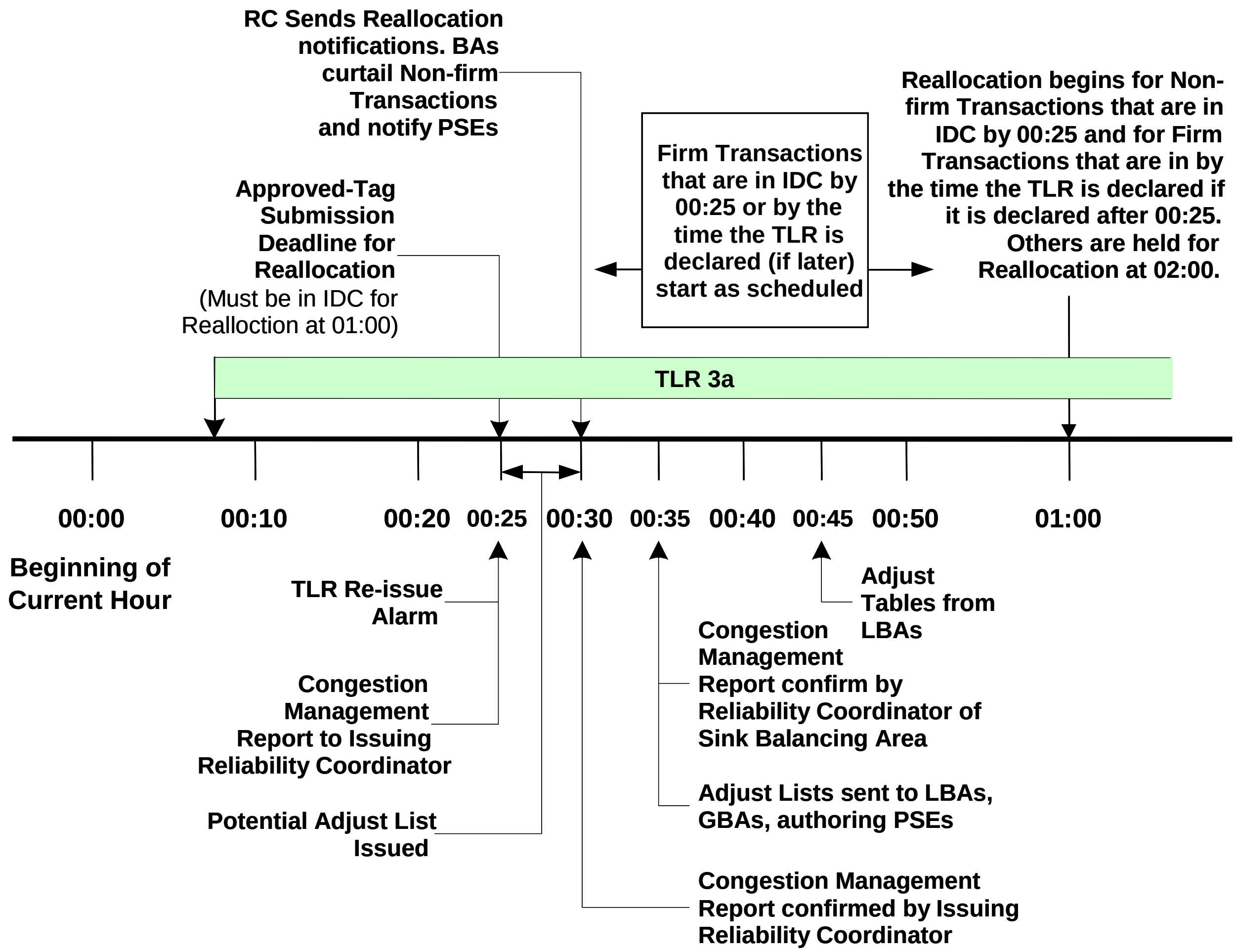


Figure 2 — Reallocation Timing for TLR 3a Called at 00:08

6.2.5. Collective Scheduling Assessment Period. At 00:25, the initiating Reliability Coordinator (the one who called and still has a TLR 3a or 5a in effect) shall run the IDC to obtain a three-part list of Interchange Transactions including their transaction status:

6.2.5.1. Interchange Transactions that may start, increase, or reload shall have a status of PROCEED, and

6.2.5.2. Interchange Transactions that must be curtailed or Interchange Transactions whose tags were submitted prior to the TLR 2 or higher being declared but were not permitted to start or increase shall have a status of CURTAILED, and

6.2.5.3. Interchange Transactions that are entered into the IDC after 00:25 shall have a status of HOLD and be considered for Reallocation at 02:00. Also, Interchange Transactions using Non-firm Point-to-Point Transmission Service submitted after TLR 2 or higher was declared ("post-tagged") but have not been allowed to start shall retain the HOLD status until given permission to PROCEED or E-Tag expires. (Note: TLR Level 2 does not hold Interchange Transactions using Firm Point-to-Point Transmission Service).

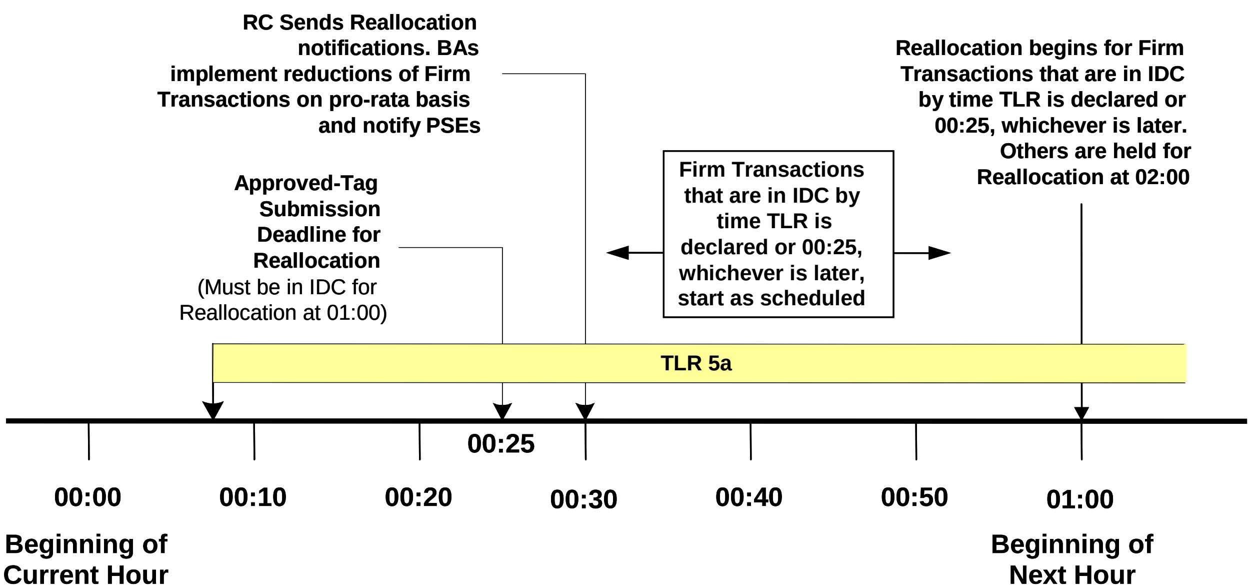


Figure 3 — Reallocation timing for TLR 5a called at 00:08.

6.2.5.4. The initiating Reliability Coordinator shall communicate the list of Interchange Transactions to the appropriate sink Reliability Coordinators via the IDC, who shall in turn communicate the list to the Sink Balancing Authorities at 00:30 for appropriate actions to implement Interchange Transactions (CURTAIL, PROCEED or HOLD). The IDC will prompt the initiating Reliability Coordinator to input the necessary information (i.e., maximum flowgate loading and curtailment requirement) into the IDC by 00:25.

6.2.5.5. Subsequent required reports before 01:00 shall allow the Reliability Coordinators to include those Interchange Transactions whose tags were submitted to the IDC after the Approved-Tag Submission Time for Reallocation and were given the HOLD status (not permitted to PROCEED). Transactions at or above the Curtailment Threshold that are not indicated as "PROCEED" on Reload/Reallocation Report shall not be permitted to start or increase the next hour.

Discussion: Note that TLR 2 does not initiate the approved tag submission deadline for Reallocation, but a TLR3a or 5a does. It is, however, important to recognize the time when a TLR 2 is called, where applicable, to determine the status of a held transaction – "CURTAILED" if tagged before the TLR was called but "HOLD" if tagged after the TLR was called.

6.2.5.6. In running the IDC, the Reliability Coordinator shall have an option to specify the maximum loading of the Constrained Facility by all Interchange Transactions using Point-to-Point Transmission Service.

Discussion: This allows the Reliability Coordinator to take into consideration SOLs or IROLs and changes in Transactions using other than Point-to-Point service taken under the Open Access Transmission Tariff. This option is needed to avoid loading the Constrained Facility to its limit with known Interchange Transactions while other factors push the facility into a SOL or IROL violation and hence triggering the declaration of a TLR 3b or 5b.

6.2.5.7. Notification of Interchange Transaction status shall be provided from the IDC to the Reliability Coordinators via an IDC Report. The Reliability Coordinators shall communicate this information to the Balancing Authorities and Transmission Operators.

Additional reporting and communications details on information posted from the IDC to the NERC TLR website are contained in Appendix E.

6.2.6. **Customer Preferences on Timing to Call TLR 3a or 5a.** Reliability Coordinators shall leave a TLR 2 and call a TLR 3a as soon as possible (but no later than 30 minutes) to initiate the Approved-Tag Submission Deadline and start reallocating Transactions. Nevertheless, recognizing the approved tag submission deadline for Reallocation, from a Transmission Customer perspective, it is preferable that the Reliability Coordinator call a TLR 3a within a certain time period to allow for tag preparation and submission. See Figure 4.

Discussion: A Reliability Coordinator calls a TLR 2 or 3a whenever it deems necessary to indicate that a transmission facility is approaching its SOL or IROL. It is envisioned, though not required, that a TLR 2 or 3a is preceded by a period of a TLR 1 declaration, hence Transmission Customers should normally have advance notice of a potential constraint. For example, a TLR 3a initiated during the period 01:00 to 01:25 would allow the Purchasing-Selling Entity to submit a Tag for entry into the IDC by the Approved-Tag Submission Deadline for Reallocation at 02:00. See Figure 4. However, the preferred time period to declare a TLR 3a or 5a would be between 00:40 (when tags for Next Hour Market have been submitted) and 01:15. This will allow the Transmission Customers a range of 15 to 35 minutes to prepare and submit tags. (Note: In this situation, the Reliability Coordinator would need to reissue the TLR 3a at 01:00.)

It must be emphasized that the preferred time period is not a requirement, and should not in any way impede a Reliability Coordinator's ability to declare a TLR 3a, 3b, 4, 5a, or 5b whenever the need arises.

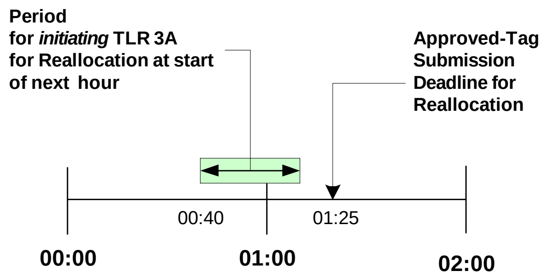


Figure 4. "Ideal" time for issuing TLR 3a for Reallocation at 02:00.

7. Interchange Transaction Curtailments During TLR Level 3b

Introduction

This section provides the details for implementing TLR Level 3b, which curtails Interchange Transactions using Non-firm Point-to-Point Transmission Service to assist the Reliability Coordinator to recover from SOL or IROL violations.

TLR Level 3b curtails Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold. (See **Requirement 2.4, "TLR Level 3b.")**. Furthermore, *all* new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold during the TLR 3b implementation period are halted or held. Transactions using Firm Point-to-Point Transmission Service will be allowed to start if they are submitted to the IDC within specific time limits as explained in Appendix F, "Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service." Those Interchange Transactions using Firm Point-to-Point Transmission Service that are not submitted to the IDC within these time limits will be held.

Requirements

7.1. The Reliability Coordinator shall be allowed to call a TLR 3b at any time to help mitigate a SOL or IROL violation.

7.2. The Reliability Coordinator shall consider only those Interchange Transactions at or above the Curtailment Threshold for curtailment, holding, or halting.

7.3. The Reliability Coordinator shall curtail existing Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to provide the required relief on the Constrained Facility.

7.4. The Reliability Coordinator shall curtail additional Interchange Transactions using Non-firm Point-to-Point Transmission Service to provide transmission capacity for Interchange Transactions using Firm Point-to-Point Transmission Service if those Interchange Transactions using Firm Point-to-Point Transmission Service are scheduled to start during the current hour or the following hour.

7.5. The Reliability Coordinator shall not allow existing Interchange Transactions using Non-firm Point-to-Point Transmission Service that are not curtailed to increase (they may flow at the same or reduced level).

7.6. The Reliability Coordinator shall not reallocate Interchange Transactions using Non-firm Point-to-Point Transmission Service during a TLR 3b.

7.7. The Reliability Coordinator shall allow Interchange Transactions using Firm Point-to-Point Transmission Service to start as explained in Appendix F, "Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service."

7.8. The Reliability Coordinator shall progress to TLR Level 5b as necessary if there is still insufficient transmission capacity for Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled after all Interchange Transactions using Non-firm Point-to-Point Transmission Service have been curtailed.

7.9. The IDC shall issue ADJUST Lists to the Generation and Load Balancing Authority Areas and the Purchasing-Selling Entity who submitted the tag. The ADJUST List will include:

7.9.1. Interchange Transactions using Non-firm Point-to-Point Transmission Service that are to be curtailed, halted, or held during current and next hours.

7.9.2. Interchange Transactions using Firm Point-to-Point Transmission Service that were entered after 00:25 or issuance of TLR 3b (see Case 3 in Appendix F).

7.10. The Sink Balancing Authority shall send the ADJUST Lists back to the IDC as soon as possible to ensure the most accurate calculations for actions subsequent to the TLR 3b being called.

7.11. The Reliability Coordinator shall be allowed to call a TLR Level 3a as soon as the SOL or IROL violation that caused the TLR 3b to be called has been mitigated.

7.11.1. If the TLR Level 3a is called before the hour 01, then a Reallocation shall be computed for the start of that hour.

7.11.2. Transactions must be in the IDC by the Approved-tag Submission Deadline for Reallocation (see Requirement 6.2).

Appendices for Transmission Loading Relief Standard

Appendix A. Transaction Management and Curtailment Process.

Appendix B. Transaction Curtailment Formula.

Appendix C. Sample NERC Transmission Loading Relief Procedure Log.

Appendix D. Examples for Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service.

Appendix E. How the IDC Handles Reallocation.

Section E1: Summary of IDC Features that Support Transaction Reloading/Reallocation.

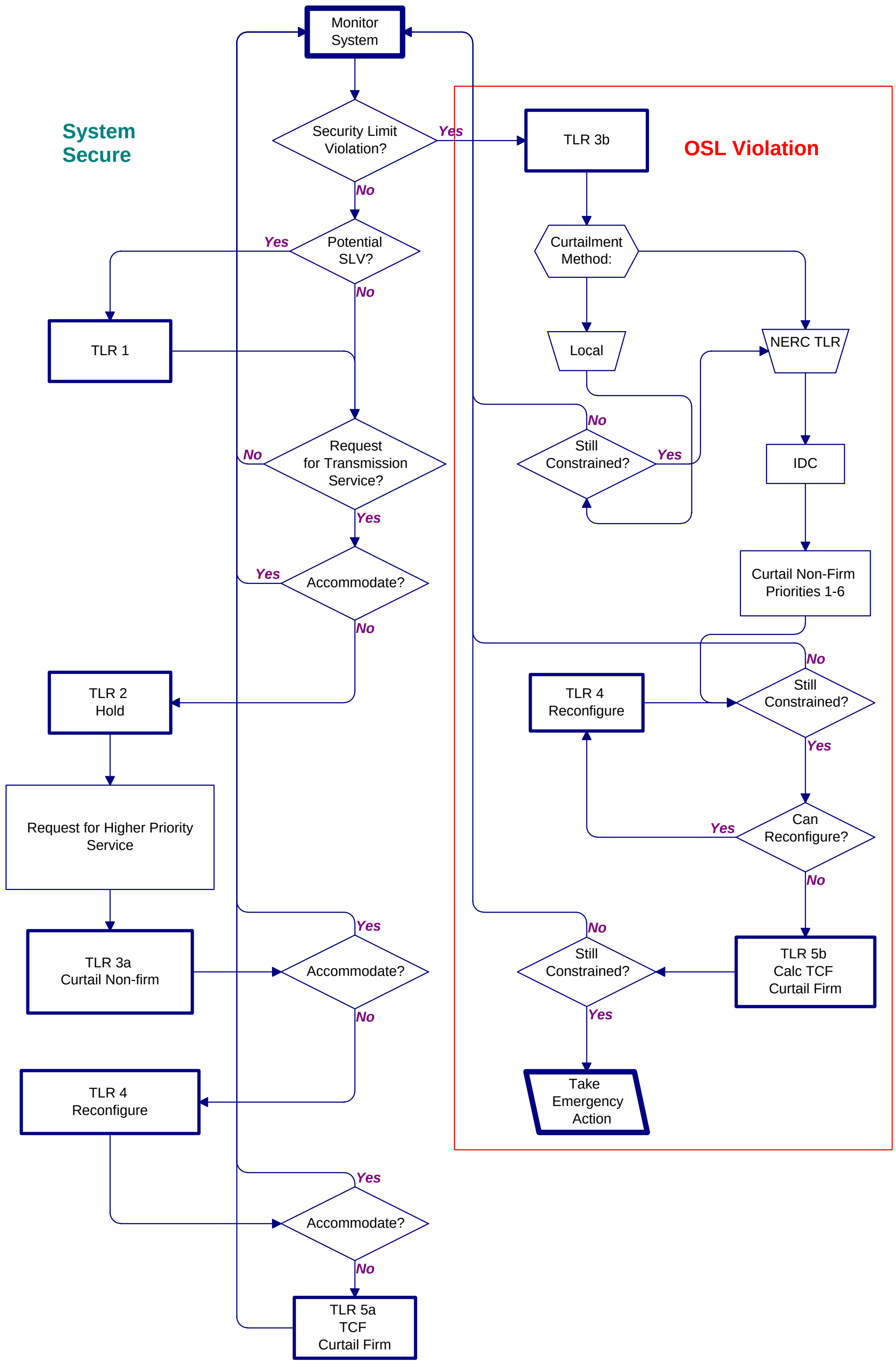
Section E2: Timing Requirements.

Appendix F. Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.

Appendix G. Examples of On-Path and Off-Path Mitigation.

Appendix A. Transaction Management and Curtailment Process

This flowchart depicts an overview of the Transaction Management and Curtailment process. Detailed decisions are not shown.



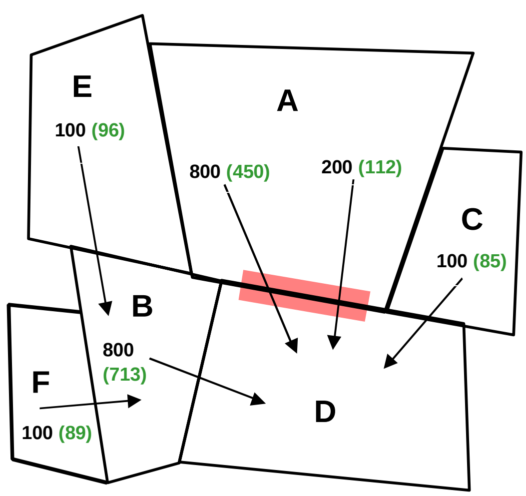
Appendix B. Transaction Curtailment Formula

Example

This example is based on the premise that a transaction should be curtailed in proportion to its Transfer Distribution Factor on the Constraints. Its effect on the interface is a combination of its size in MW and its effect based on its distribution factor.

Column	Description
1. Initial Transaction	Interchange Transaction before the TLR Procedure is implemented.
2. Distribution Factor	Proportional effect of the Transaction over the constrained interface due to the physical arrangement and impedance of the transmission system.
3. Impact on the Interface	Result of multiplying the Transaction MW by the distribution factor. This yields the MW that flow through the constrained interface from the Transaction. Performing this calculation for each Transaction yields the total flow through the constrained interface from all the Interchange Transactions. In this case, 760 MW.
4. Impact Weighting Factor	"Normalization" of the total of the Distribution Factors in Column 2. Calculated by dividing the Distribution Factor for each Transaction by the total of the Distribution Factors.
5. Weighted Maximum Interface Reduction	Multiplying the Impact on the Interface from each Transaction by its Impact Weighting Factor yields a new proportion that is a combination of the MW Impact on the Interface and the Distribution Factor.
6. Interface Reduction	Multiplying the amount needed to reduce the flow over the constrained interface (280 MW) by the normalization of the Weighted Maximum Interface Reduction yields the actual MW reduction that each Transaction must *contribute* to achieve the total reduction.
7. Transaction Reduction	Now divide by the Distribution Factor to see how much the Transaction must be reduced to yield the result calculated in Column 7. Note that the reductions for the first two Interchange Transactions (A-D (1) and A-D (2) are in proportion to their size since their distribution factors are equal.
8. New Transaction Amount	Subtracting the Transaction Reduction from the Initial Transaction yields the New Transaction Amount.
9. Adjusted Impact on Interface	A check to ensure the new constrained interface MW flow has been reduced to the target amount.

	Allocation based on Weighted Impact								
	1	2	3	4	5	6	7	8	9
Transaction ID	Initial Transaction	Distribution Factor	(1)*(2) Impact On Interface	(2)/(2TOT) Impact weighting factor	(3)*(4) Weighted Max Interface Reduction	(5)*(Relief Requested) /(5 Tot) Interface Reduction	(6)/(2) Transaction Reduction	(1)-(7) New Transaction Amount	(8)*(2) Adjusted Impact On Interface
Example 1									
A-D(1)	800	0.6	480	0.34	164.57	209.73	349.54	450.46	270.27
A-D(2)	200	0.6	120	0.34	41.14	52.43	87.39	112.61	67.57
B-D	800	0.15	120	0.09	10.29	13.11	87.39	712.61	106.89
C-D	100	0.2	20	0.11	2.29	2.91	14.56	85.44	17.09
E-B	100	0.05	5	0.03	0.14	0.18	3.64	96.36	4.82
F-B	~~100~~	~~0.15~~	~~15~~	~~0.09~~	~~1.29~~	~~1.64~~	~~10.92~~	~~89.08~~	~~13.36~~
	2100	**1.75**	**760**		**219.71**	**280.00**	**553.45**	**1546.55**	**480.00**
Example 2									
A-D(1)	1000	0.6	600	0.52	313.04	262.16	436.93	563.07	337.84
B-D	800	0.15	120	0.13	15.65	13.11	87.39	712.61	106.89
C-D	100	0.2	20	0.17	3.48	2.91	14.56	85.44	17.09
E-B	100	0.05	5	0.04	0.22	0.18	3.64	96.36	4.82
F-B	~~100~~	~~0.15~~	~~15~~	~~0.13~~	~~1.96~~	~~1.64~~	~~10.92~~	~~89.08~~	~~13.36~~
	2100	**1.15**	**760**		**334.35**	**280.00**	**553.45**	**1546.55**	**480.00**
Example 3									
A-D(1A)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(1B)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(1C)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(1D)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(2)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
B-D	800	0.15	120	0.04	5.07	13.11	87.39	712.61	106.89
C-D	100	0.2	20	0.06	1.13	2.91	14.56	85.44	17.09
E-B	100	0.05	5	0.01	0.07	0.18	3.64	96.36	4.82
F-B	~~100~~	~~0.15~~	~~15~~	~~0.04~~	~~0.63~~	~~1.64~~	~~10.92~~	~~89.08~~	~~13.36~~
	2100	**3.55**	**760**		**108.31**	**280.00**	**553.45**	**1546.55**	**480.00**



Appendix C. Sample NERC Transmission Loading Relief Procedure Log

SAVE FILE DIRECTORY:

NERC TRANSMISSION LOADING RELIEF (TLR) PROCEDURE LOG

FILE SAVED AS: .XLS

INCIDENT:	DATE:	IMPACTED RELIABILITY COORDINATOR:	ID NO:

INITIAL CONDITIONS

Limiting Flowgate (LIMIT)	Rating	Contingent Flowgate (CONT.)	ODF

TLR Levels

0: TLR Incident Canceled
1. Notify Reliability Coordinators of potential problems.
2: Halt additional transactions that contribute to the overload
3a and 3b: Curtail transactions using Non-firm Transmission Service
4. Reconfigure to continue firm transactions if needed.
5a and 5b: Curtail Transactions using Firm Transmission Service.
6: Implement emergency procedures.

Priorities

NX	Next Hour Market Service
NS	Service over secondary receipt and delivery points
NH	Hourly Service
ND	Daily Service
NW	Weekly Service
NM	Monthly Service
NN	Non-firm imports for native load and network customers from non-designated network resources
F	Firm Service

TLR ACTIONS

LEVEL	TIME	Priority	TLR 3,5 No. TX Curtail	TLR 3,5 MW Curtai	MW Flow Limiting Element Present	Post Cont.	Cont. Elem't Present	COMMENTS ABOUT ACTIONS

Appendix D. Examples for Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service

The NERC "**Parallel Flow Calculation Procedure Reference Document**" provides additional information about the criteria used to include generators in the IDC calculation process.

Example of Results of Calculation Method

An example of the output of the IDC calculation of curtailment of firm Transmission Service is provided below for the specific Constrained Facility identified in the *Book of Flowgates* as Flowgate 1368. In this example, a total Firm Point-to-Point contribution to the Constrained Facility, as calculated by the IDC, is assumed to be 21.8 MW.

The table below presents a summary of each Balancing Authority's responsibility to provide relief to the Constrained Facility due to its Network Integration Transmission Service and service to Native Load contribution to the Constrained Facility. In this example, Balancing Authority LAGN would be requested to curtail 17.3 MW of its total of 401.1 MW of flow contribution on the Constrained Facility. See the "**Parallel Flow Calculation Procedure Reference Document**" for additional details regarding the information illustrated in the table (e. g. Scaled P Max and Flowgate NNative Load MW).

In summary, Interchange transactions would be curtailed by a total of 21.8 MW and Network Integration Transmission Service and service to Native Load would be curtailed by a total of 178.2 MW by the five Balancing Authorities identified in the table. These curtailments would provide a total of 200.0 MW of relief to the Constrained Facility.

Sink Reliability Coordinator	Service Point	Scaled P Max	Flowgate NNative Load MW	Current NNative Load Relief	NNative Load Responsibility		NNative Load Responsibility Acknowledgement	
					Inc/Dec	Current Hr	Acknowledge Time	Total MW Resp.
EES	EES	8429.7	2991.4	0.0	128.9	128.9	13:44	128.9
EES	LAGN	1514.0	718.6	0.0	31.0	31.0	13:44	31.0
SOCO	SOCO	5089.2	401.1	0.0	17.3	17.3	13:44	17.3
SWPP	CLEC	235.7	18.0	0.0	0.8	0.8	13:42	0.8
SWPP	LEPA	22.8	4.1	0.0	0.2	0.2	13:42	0.2
Total				**0.0**				

Appendix E. How the IDC Handles Reallocation

The IDC algorithms reflect the Reallocation and reloading principles in this Appendix, as well as the reporting requirements, and status display. The IDC will obtain the Tag Submittal Time from the Tag Authority and post the Reloading/Reallocation information to the NERC TLR website.

A summary of IDC features that support the Reallocation process is provided in Attachment E1. Details on the interface and display features are provided in Attachment E2. Refer to Version 1.7.095 NERC Transaction Information Systems Working Group (TISWG) *Electronic Tagging Functional Specification* for details about the E-Tag system.

E1. Summary of IDC Features that Support Transaction Reloading/Reallocation

The following is a summary of IDC features and E-Tag interface that support Reloading/Reallocation:

Information posted from IDC to NERC TLR website.

1. Restricted directions (all source/sink combinations that impact a Constrained Facility(ies) with TLR 2 or higher) will be posted to the NERC TLR website and updated as necessary.

2. TLR Constrained Facility status and Transfer Distribution Factors will continue to be posted to NERC TLR website.

3. Lowest priority of Interchange Transactions (marginal "bucket") to be Reloaded/Reallocated next-hour on each TLR Constrained Facility will be posted on NERC TLR website. This will provide an indication to the market of priority of Interchange Transactions that may be Reloaded/Reallocated the following hours.

IDC Logic, IDC Report, and Timing

1. The Reliability Coordinator will run the IDC the Reloading/Reallocation report at approximately 00:26. The IDC will prompt the Reliability Coordinator to enter a maximum loading value. The IDC will alarm if the Reliability Coordinator does not enter this value and issue a report by 00:30 or change from TLR 3a Level. The Report will be distributed to Balancing Authorities and Transmission Operators at 00:30. This process repeats every hour as long as the approved tag submission deadline for Reallocation is in effect (or until the TLR level is reduced to 1 or 0).

2. For Interchange Transactions in the restricted directions, tags must be submitted to the IDC by the approved tag submission deadline for Reallocation to be considered for Reallocation next-hour. The time stamp by the Tag Authority is regarded the official tag submission time.

3. Tags submitted to IDC after the approved tag submission deadline for Reallocation will not be allowed to start or increase but will be considered for Reallocation the next hour.

4. Interchange Transactions in restricted directions that are not indicated as "PROCEED" on the Reload/Reallocation Report will not be permitted to start or increase next hour.

Reloading/Reallocation Transaction Status

Reloading/Reallocation status will be determined by the IDC for all Interchange Transactions. The Reloading/Reallocation status of each Interchange Transaction will be listed on IDC reports and NERC TLR website as appropriate. An Interchange Transaction is considered to be in a restricted direction if it is at or above the Curtailment Threshold. Interchange Transactions below the Curtailment Threshold are unrestricted and free to flow subject to all applicable Reliability Standards and tariff rules.

1. **HOLD.** Permission has not been given for Interchange Transaction to start or increase and is waiting for the next Reloading/Reallocation evaluation for which it is a candidate. Interchange Transactions with E-tags submitted to the Tag Authority prior to TLR 2 or higher being declared (pre-tagged) will change to CURTAILED Status upon evaluation that does not permit them to start or increase. Transactions with E-tags submitted to Tag Authority after TLR 2 or higher was declared (post-tagged) will retain HOLD Status until given permission to proceed or E-Tag expires.

2. **CURTAILED**. Transactions for which E-Tags were submitted to Tag Authority prior to TLR 2 or higher being declared (pre-tagged) and ordered to be curtailed totally, curtailed partially, not permitted to start, or not permitted to increase. Interchange Transactions (pre-tagged or post-tagged) that were flowing and ordered to be reduced or totally curtailed. The Balancing Authority will indicate to the IDC through the E-Tag adjustment table the Interchange Transaction's curtailed values.

3. **PROCEED**: Interchange Transaction is flowing or has been permitted to flow as a result of Reloading/Reallocation evaluation. The Balancing Authority will indicate through the E-Tag adjustment table to IDC if Interchange Transaction will reload, start, or increase next-hour per Purchasing-Selling Entity's energy schedule as appropriate.

Reallocation/Reloading Priorities

1. Interchange Transaction candidates are ranked for loading and curtailment by priority as per Section 4, "Principles for Mitigating Constraints On and Off the Contract Path." This is called the "Constrained Path Method," or CPM. (secondary, hourly, daily, … firm etc). Interchange Transactions are curtailed and loaded pro-rata within priority level per TLR algorithm.

2. Reloading/Reallocation of Interchange Transactions are prioritized first by priority per CPM. E-Tags must be submitted to the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is scheduled to start or increase to be considered for Reallocation.

3. During Reloading/Reallocation, Interchange Transactions using lower priority Transmission Service will be curtailed pro-rata to allow higher priority transactions to reload, increase, or start. Equal priority Interchange Transactions will not reload, start, or increase by pro-rata Curtailment of other equal priority Interchange Transactions.

4. Reloading of Interchange Transactions using Non-firm Transmission Service with CURTAILED Status will take precedence over starting or increasing of Interchange Transactions using Non-firm Transmission Service of the same priority with PENDING Statuses.

5. Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled under TLR 3a as long as their E-Tag was received by the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is due to start or increase, regardless of whether the E-tag was submitted to the Tag Authority prior to TLR 2 or higher being declared or not. If this is the initial issuance of the TLR 3a, Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled as long as their E-Tag was received by the IDC by the time the TLR is declared.

Total Flow Value on a Constrained Facility for Next Hour

1. The Reliability Coordinator will calculate the change in net flow on a Constrained Facility due to Reallocation for the next hour based on:

- Present constrained facility loading, present level of Interchange Transactions, and Balancing Authorities NNative Load responsibility (TLR Level 5a) impacting the Constrained Facility,

- SOLs or IROLs, known interchange impacts and Balancing Authority NNative Load responsibility (TLR Level 5a) on the Constrained Facility the next hour, and

- Interchange Transactions scheduled to begin the next hour.

2. The Reliability Coordinator will enter a maximum loading value for the constrained facility into the IDC as part of issuing the Reloading/Reallocation report.

3. The Reliability Coordinator is allowed to call for TLR 3a or 5a when approaching a SOL or IROL to allow maximum transactional flow next hour, and to manage flows without violating transmission limits.

4. The simultaneous curtailment and Reallocation for a Constrained Facility is allowed. This reduces the flow over the Constrained Facility while allowing Interchange Transactions using higher priority Transmission Service to start or increase the next hour. This may be used to accommodate change in flow next-hour due to changes other than Point-to-Point Interchange Transactions while respecting the priorities of Interchange Transactions flowing and scheduled to flow the next hour. The intent is to reduce the need for using TLR 3b, which prevents new Interchange Transactions from starting or increasing the next hour.

5. The Reliability Coordinator must allow Interchange Transactions to be reloaded as soon as possible. Reloading must be in an orderly fashion to prevent a SOL or IROL violation from (re)occurring and requiring holding or curtailments in the restricted direction.

E2. Timing Requirements

TLR Levels 3a and 5a Issuing/Processing Time Requirement

1. In order for the IDC to be reasonably certain that a TLR Level 3a or 5a re-allocation/reloading report in which all tags submitted by the approved tag submission deadline for Reallocation are included, the report must be generated no earlier than 00:25 to allow the 10-minute approval time for Transactions that start next hour.

2. In order to allow a Reliability Coordinator to declare a TLR Level 3a or 5a at any time during the hour, the TLR declaration and Reallocation/Reloading report distribution will be treated as independent processes by the IDC. That is, a Reliability Coordinator may declare a TLR Level 3a or 5a at any time during the course of an hour. However, if a TLR Level 3a or 5a is declared for the next hour prior to 00:25 (see Figure 5 at right), the Reallocation/Reloading report that is generated will be made available to the issuing Reliability Coordinator only for previewing purposes, and cannot be distributed to the other Reliability Coordinators or the market. Instead, the issuing Reliability Coordinator will be reminded by an IDC alarm at 00:25 to generate a new Reallocation/Reloading report that will include all tags submitted prior to the approved tag submission deadline for Reallocation.

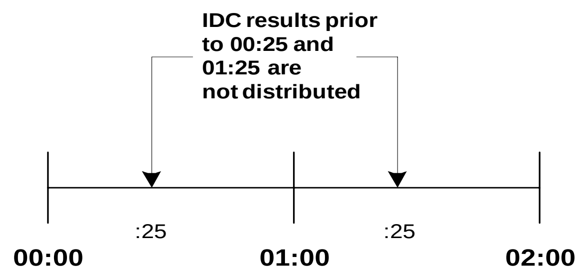


Figure 5 - IDC report may be run prior to 00:25, but results are not distributed.

3. A TLR Level 3a or 5a Reallocation/Reloading report must be confirmed by the issuing Reliability Coordinator prior to 00:30 in order to provide a minimum of 30 minutes for the Reliability Coordinators with tags sinking in its Reliability Area to coordinate the Reallocation and Reloading with the Sink Balancing Authorities. This provides only 5 minutes (from 00:25 to 00:30) for the issuing Reliability Coordinator to generate a Reallocation/Reloading report, review it, and approve it.

4. The TLR declaration time will be recorded in the IDC for evaluating transaction sub-priorities for Reallocation/Reloading purposes (see Subpriority Table, in the **IDC Calculations and Reporting** section below).

Re-Issuing of a TLR Level 2 or Higher

Each hour, the IDC will automatically remind the issuing Reliability Coordinator (via an IDC alarm) of a TLR level 2 or higher declared in the previous hour or earlier about re-issuing the TLR. The purpose of the reminder is to enable the Reliability Coordinator to Reallocate or reload currently halted or curtailed Interchange Transactions next hour. The reminder will be in the form of an alarm to the issuing Reliability Coordinator, and will take place at 00:25 so that, if the Reliability Coordinator re-issues the TLR as a TLR level 3a or 5a, all tags submitted prior to the approved tag submission deadline for Reallocation are available in the IDC.

IDC Assistance with Next Hour Point-to-Point Transactions

In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour for a TLR level 3a or 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour. In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour during a TLR level 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour as well as Balancing Authority with flows due to service to Network Customers and Native Load. The Reliability Coordinator will then be requested to provide the total incremental or decremental MW amount of flow through the Constrained Facility that can be allowed for the next hour. The value entered by the Reliability Coordinator and the

IDC-calculated amounts will be used by the IDC to identify the relief/reloading amounts (delta incremental flow value) on the constrained facility. The IDC will determine the Transactions to be reloaded, reallocated, or curtailed to make room for the Transactions using higher priority Transmission Service. The following examples show the calculation performed by IDC to identify the "delta incremental flow:"

Example 1

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	-100 MW
Expected Net flow next hour on Facility	850 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	850 MW – 800 MW = 50 MW
Amount to enter into IDC for Transactions using Point-to-Point Transmission Service	950 MW – 50 MW = 900 MW

Example 2

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	50 MW
Expected Net flow next hour on Facility	1000 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	1000 MW – 800 MW = 200 MW
Amount to enter into IDC for Transactions using Point-to-Point Transmission Service	950 MW – 200 MW = 750 MW

Example 3

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	-200 MW
Expected Net flow next hour on Facility	750 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	750 MW – 800 MW = -50 MW None are held

For a TLR levels 3b or 5b the IDC will request the Reliability Coordinator to provide the MW requested relief amount on the Constrained Facility, and will not present the current and next hour MW impact of Point-to-Point transactions. The Reliability Coordinator-entered requested relief amount will be used by the IDC to determine the Interchange Transaction Curtailments and flows due to service to Network Customers and Native Load (TLR Level 5b) in order to reduce the SOL or IROL violation on the Constrained Facility by the requested amount.

IDC Calculations and Reporting

At the time the TLR report is processed, the IDC will use all candidate Interchange Transactions for Reallocation that met the approved tag submission deadline for Reallocation plus those Interchange Transactions that were curtailed or halted on the previous TLR action of the same TLR event. The IDC will calculate and present an Interchange Transactions Halt/Curtailment list that will include reload and Reallocation of Interchange Transactions. The Interchange Transactions are prioritized as follows:

1. All Interchange Transactions will be arranged by Transmission Service Priority according to the Constrained Path Method. These priorities range from 1 to 6 for the various non-firm Transmission Service products (TLR levels 3a and 3b). Interchange Transactions using Firm Transmission Service (priority 7) are used only in TLR levels 5a and 5b. Next-Hour Market Service is included at priority 0.
2. In a TLR Level 3a the Interchange Transactions using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status. Solely for the purpose of identifying which Interchange Transactions to be loaded under a TLR 3a, various MW levels of an Interchange Transaction may be in different sub-priorities. The sub-priorities are shown in the following table:

Priority	**Purpose**	**Explanation and Conditions**
S1	To allow a flowing Interchange Transaction to maintain or reduce its current MW amount in accordance with its energy profile.	The MW amount is the lowest between currently flowing MW amount and the next-hour schedule. The currently flowing MW amount is determined by the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.
S2	To allow a flowing Interchange Transaction that has been curtailed or halted by TLR to reload to the *lesser* of its current-hour MW amount or next-hour schedule in accordance with its energy profile.	The Interchange Transaction MW amount used is determined through the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.
S3	To allow a flowing Transaction to increase from its current-hour schedule to its next-hour schedule in accordance with its energy profile.	The MW amounts used in this sub-priority is determined by the e-tag ENERGY PROFILE table. If the calculated amount is negative, zero is used instead.

Priority	Purpose	Explanation and Conditions
S4	To allow a Transaction that had never started and was submitted to the Tag Authority after the TLR (level 2 or higher) has been declared to begin flowing (i.e., the Interchange Transaction never had an active MW and was submitted to the IDC *after* the first TLR Action of the TLR Event had been declared.)	The Transaction would not be allowed to start until all other Interchange Transactions submitted prior to the TLR with the same priority have been (re)loaded. The MW amount used is the sub-priority is the next-hour schedule determined by the e-tag ENERGY PROFILE table.

Examples of Interchange Transactions using Non-firm Transmission Service sub-priority settings begin in the **Transaction Sub-priority Examples** following sections.

3. All Interchange Transactions using Firm Transmission Service will be put in the same priority group, and will be Curtailed/Reallocated pro-rata, independent of their current status (curtailed or halted) or time of submittal with respect to TLR issuance (TLR level 5a). Under a TLR 5a, all Interchange Transactions using Non-firm Transmission Service that is at or above the Curtailment Threshold will have been curtailed and hence sub-prioritizing is not required.

All Interchange Transactions processed in a TLR are assigned one of the following statuses:

PROCEED: The Interchange Transaction has started or is allowed to start to the next hour MW schedule amount.

CURTAILED: The Interchange Transaction has started and is curtailed due to the TLR, or it had not started but it was submitted prior to the TLR being declared (level 2 or higher).

HOLD: The Interchange Transaction had never started and it was submitted after the TLR being declared – the Interchange Transaction is held from starting next hour or the transaction had never started and it was submitted to the IDC after the Approved-Tag Submission Deadline – the Interchange Transaction is to be held from starting next hour and is not included in the Reallocation calculations until following hour.

Upon acceptance of the TLR Transaction Reallocation/reloading report by the issuing Reliability Coordinator, the IDC will generate a report to be sent to NERC that will include the PSE name and Tag ID of each Interchange Transaction in the IDC TLR report. The Interchange Transaction will be ranked according to its assigned status of HOLD, CURTAILED or PROCEED. The reloading/Reallocation report will be made available at NERC's public TLR website, and it is NERC's responsibility to format and publish the report.

Tag Reloading for TLR Levels 1 and 0

When a TLR Level 1 or 0 is issued, the Constrained Facility is no longer under SOL or IROL violation and all Interchange Transactions are allowed to flow. In order to provide the Reliability Coordinators with a view of the Interchange Transactions that were halted or curtailed on previous TLR actions (level 2 or higher) and are now available for reloading, the IDC provides such information in the TLR report.

New Tag Alarming

Those Interchange Transactions that are at or above the Curtailment Threshold and are *not* candidates for Reallocation because the tags for those Transactions were not submitted by the approved tag submission deadline for Reallocation will be flagged as HOLD and must not be permitted to start or increase during the next hour. To alert Reliability Coordinators of those Transactions required to be held, the IDC will generate a report (for viewing within the IDC only) at various times. The report will include a list of all HOLD Transactions. In order not to overwhelm the Reliability Coordinator with alarms, only those who issued the TLR and those whose Transactions sink within their Reliability Area will be alarmed. An alarm will be issued for a given tag only once and will be issued for all TLR levels for which halting new Transactions is required: TLR Level 2, 3a, 3b, 5a and 5b.

Tag Adjustment

The Interchange Transactions with statuses of HOLD, CURTAILED or PROCEED must be adjusted by a Tag Authority or Tag Approval entity. Without the tag adjustments, the IDC will assume that Interchange Transactions were not curtailed/held and are flowing at their specified schedule amounts.

1. Interchange Transactions marked as CURTAILED should be adjusted to a cap equal to, or at the request of the originating PSE, less than the reallocated amount (shown as the MW CAP on the IDC report). This amount may be zero if the Transaction is fully curtailed.
2. Interchange Transaction marked as PROCEED should be adjusted to reload (NULL or to its MW level in accordance with its Energy Profile in the adjusted MW in the E-Tag) if the Interchange Transaction has been previously adjusted; otherwise, if the Interchange Transaction is flowing in full, the Tag Authority need not issue an adjust.
3. Interchange Transactions marked as HOLD should be adjusted to 0 MW.

Special Tag Status

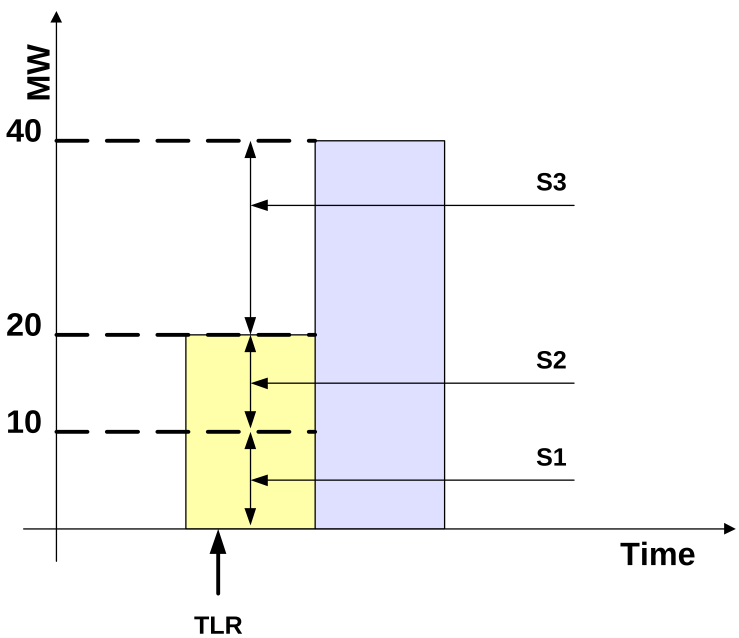
There are cases in which a tag may be marked with a composite state of ATTN_REQD to indicate that tag Authority/Approval failed to communicate or there is an inconsistency between the validation software of different tag Authority/Approval entities. In this situation, the tag is no longer subject to passive approval and its status change to IMPLEMENT may take longer than 10 minutes. Under these circumstances, the IDC may have a tag that is issued prior to the Tag Submittal Deadline that will not be a candidate for Reallocation. Such tags, when approved by the Tag Authority, will be marked as HOLD and must be halted.

Transaction Sub-Priority Examples

The following describes examples of Interchange Transactions using Non-firm Transmission Service sub-priority setting for a Interchange Transaction under different circumstances of current-hour and next-hour schedules and active MW flowing as modified by tag adjust table in E-Tag.

Example 1 – Transaction curtailed, next-hour Energy Profile is higher

Energy Profile: Current hour	20 MW
Actual flow following curtailment: Current hour	10 MW
Energy Profile: Next hour	40 MW

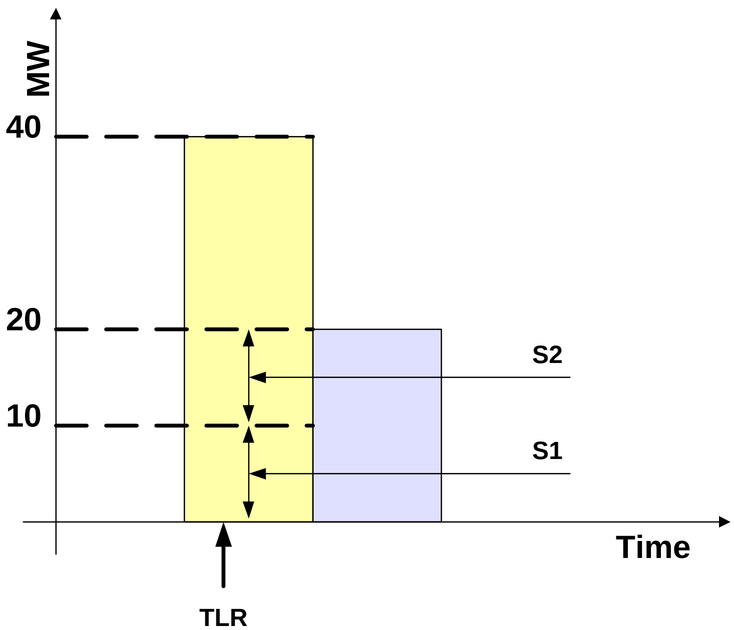


Sub-priorities for Transaction MW:

Sub-Priority	*MW Value*	*Explanation*
S1	10 MW	Maintain current curtailed flow
S2	+10 MW	Reload to current hour Energy Profile
S3	+20 MW	Load to next hour Energy Profile
S4		

Example 2 – Transaction curtailed, next-hour Energy Profile is lower

Energy Profile: Current hour	40 MW
Actual flow following curtailment: Current hour	10 MW
Energy Profile: Next hour	20 MW

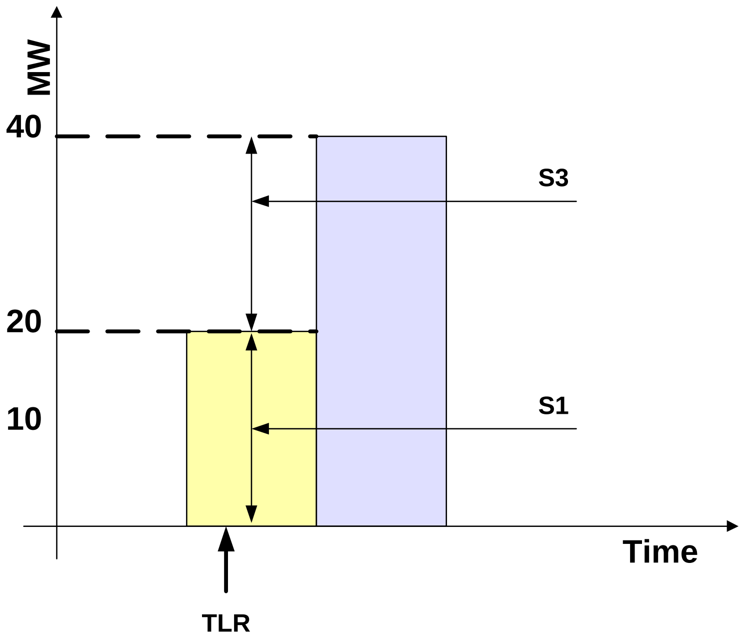


Sub-priorities for Transaction MW:

Sub-Priority	***MW Value***	***Explanation***
S1	10 MW	Maintain current curtailed flow
S2	+10 MW	Reload to *lesser* of current and next-hour Energy Profile
S3	+0 MW	Next-hour Energy Profile is 20MW, so no change in MW value
S4		

Example 3 – Transaction not curtailed, next-hour Energy Profile is higher

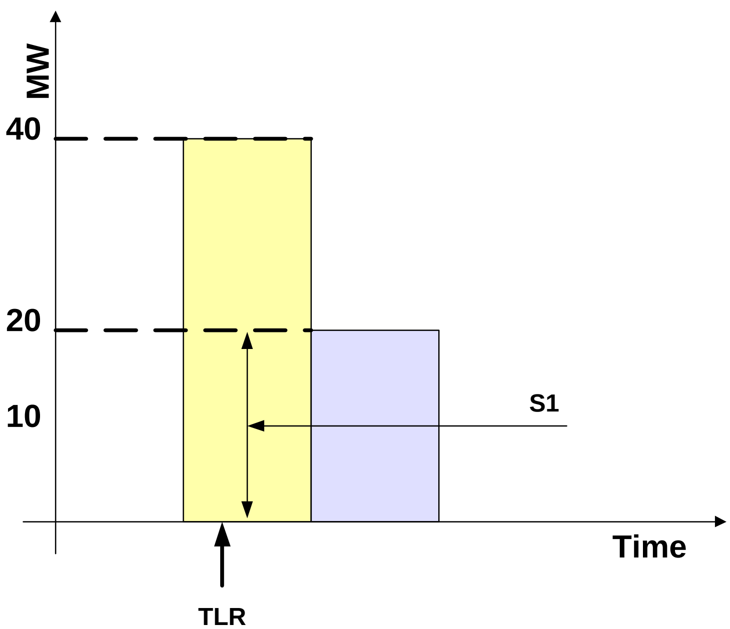
Energy Profile: Current hour	20 MW
Actual flow following curtailment: Current hour	20 MW (no curtailment)
Energy Profile: Next hour	40 MW



Sub-Priority	*MW Value*	*Explanation*
S1	20 MW	Maintain current flow (not curtailed)
S2	+0 MW	Reload to *lesser* of current and next-hour Energy Profile
S3	+20 MW	Next-hour Energy Profile is 40MW
S4		

Example 4 – Transaction not curtailed, next-hour Energy Profile is lower

Energy Profile: Current hour	40 MW
Actual flow following curtailment: Current hour	40 MW (no curtailment)
Energy Profile: Next hour	20 MW

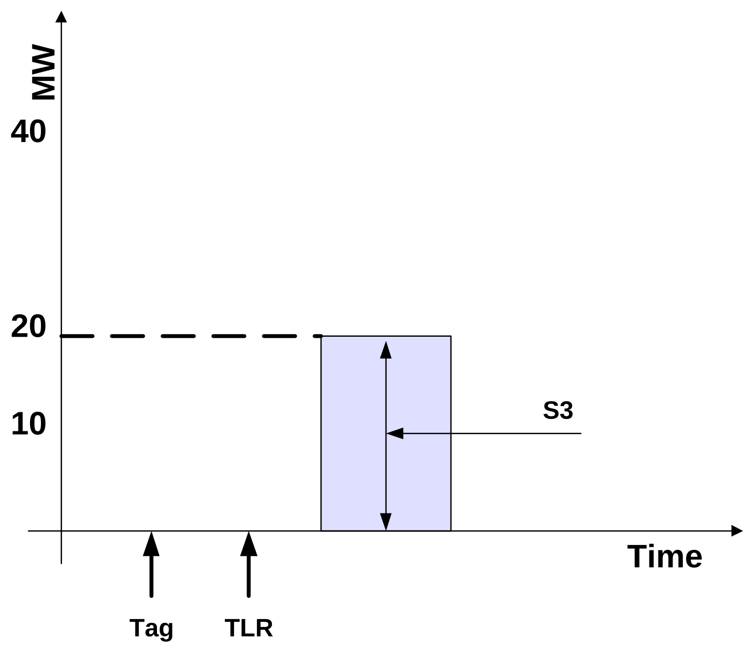


Sub-priorities for Transaction MW:

Sub-Priority	***MW Value***	***Explanation***
S1	20 MW	Reduce flow to next-hour Energy Profile (20MW)
S2	+0 MW	Reload to *lesser* of current and next-hour Energy Profile
S3	+0 MW	Next-hour Energy Profile is 20MW
S4		

Example 5 — TLR Issued before Transaction was scheduled to start

Energy Profile: Current hour	0 MW
Actual flow following curtailment: Current hour	0 MW (Transaction scheduled to start *after* TLR initiated)
Energy Profile: Next hour	20 MW



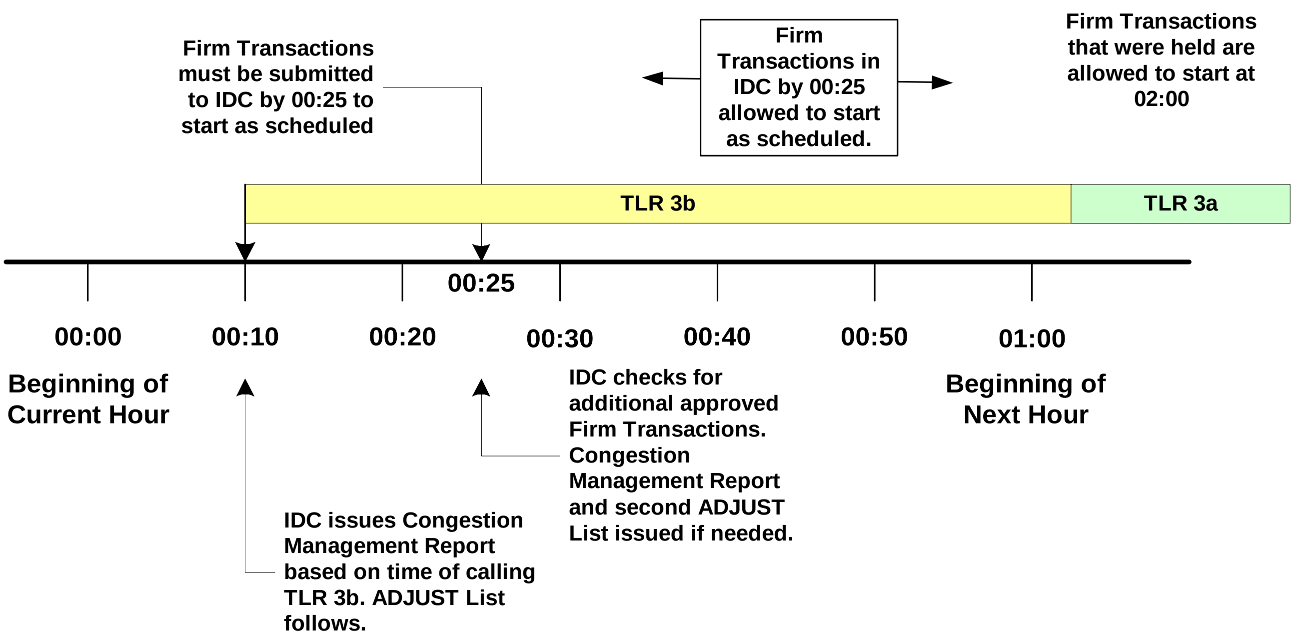
Sub-Priority	*MW Value*	*Explanation*
S1	0 MW	Transaction was not allowed to start
S2	+0 MW	Transaction was not allowed to start
S3	+20 MW	Next-hour Energy Profile is 20MW
S4	+0	Tag submitted prior to TLR

Appendix F. Considerations for Interchange Transactions

Using Firm Point-to-Point Transmission Service

The following cases explain the circumstances under which an Interchange Transaction using Firm Point-to-Point Transmission Service will be allowed to start as scheduled during a TLR 3b:

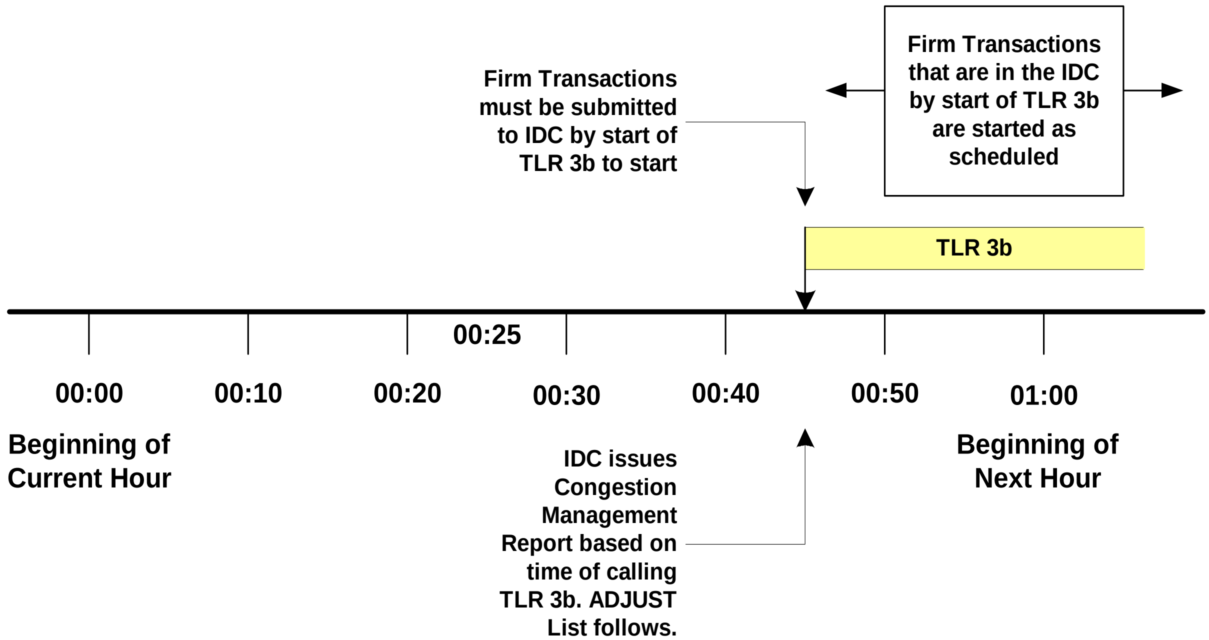
Case 1: TLR 3b is called between 00:00 and 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to IDC by 00:25.



1. The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.
2. The IDC will issue an ADJUST List based upon the time the TLR 3b is called. The ADJUST List will include curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled.
3. At 00:25, the IDC will check for additional Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by that time and issue a second ADJUST List if those additional Interchange Transactions are found.
4. All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.
5. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled.
6. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC after 00:25 will be held.

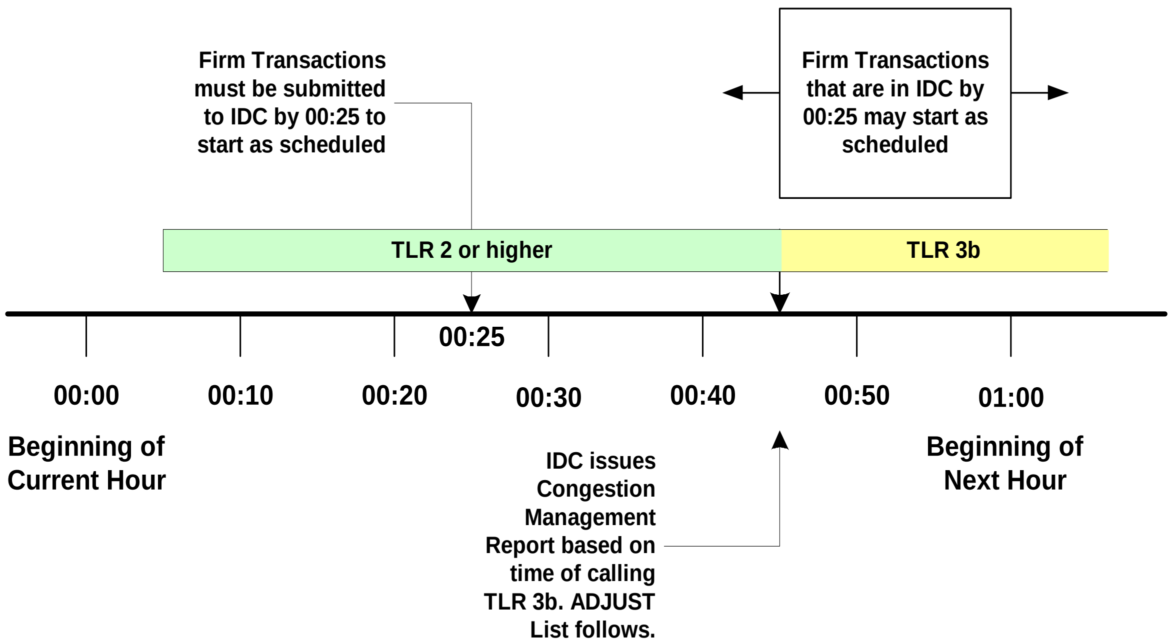
7. Once the SOL or IROL violation is mitigated, the Reliability Coordinator shall call a TLR Level 3a (or lower). If a TLR Level 3a is called:
    a. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled at 02:00.
    b. Interchange Transactions using Non-firm Point-to-Point Transmission Service that were held may then be reallocated to start at 02:00.

Case 2: TLR 3b is called after 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC no later than the time at which the TLR 3b is called.



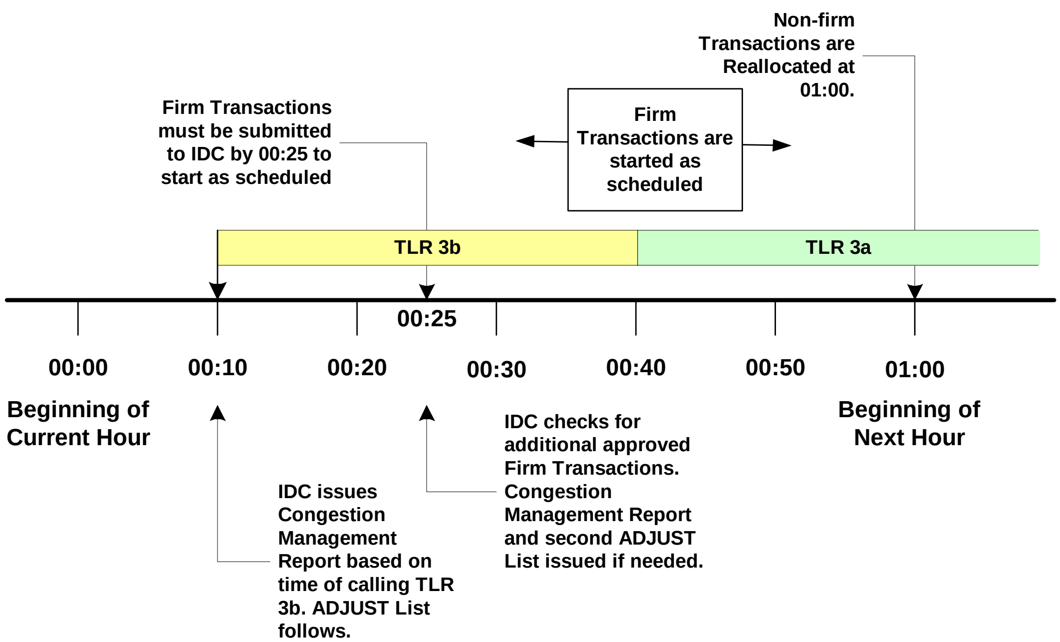
1. The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.
2. The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start at as scheduled.
3. All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.
4. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by the time the TLR 3b was called will be allowed to start at as scheduled.
5. Interchange Transaction using Firm Point-to-Point Transmission Service that were submitted to the IDC after the TLR 3b was called will be held until the next issuance for TLR (either TLR 3b, 3a, or lower level).

Case 3. TLR 2 or higher is in effect, a TLR 3b is called after 00:25, and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC by 00:25.



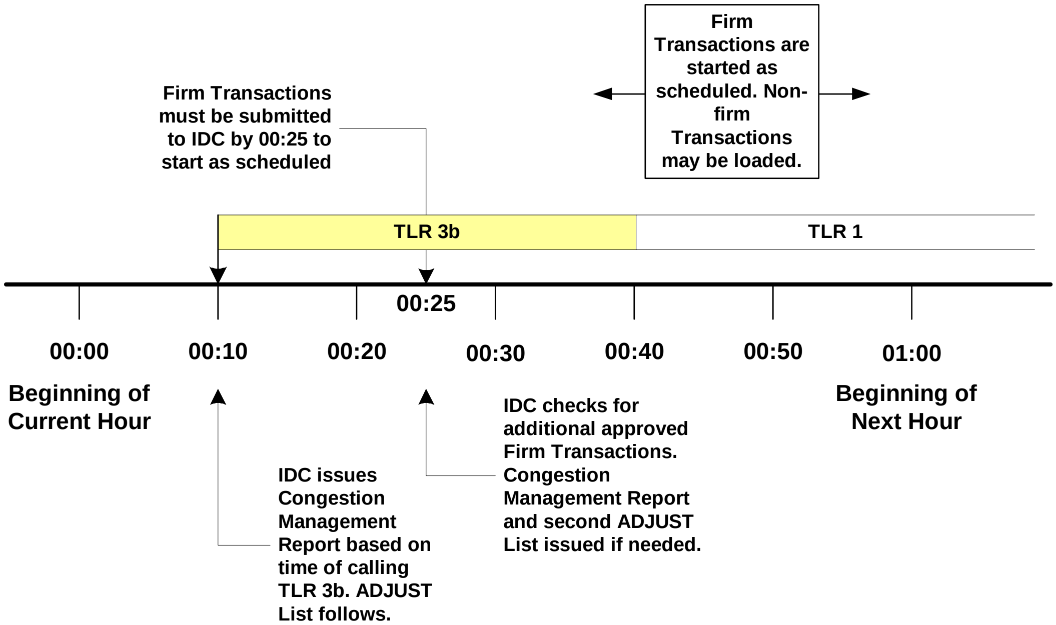
If a TLR 2 or higher has been issued and 3B is subsequently issued, then only those Interchange Transactions using Firm Point-to-Point Transmission Service that had been submitted to the IDC by 00:25 will be allowed to start as scheduled. All other Interchange Transactions are held.

Case 4. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 3a is called at 00:40.



1. Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 3a.
2. All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled if in by the time the 3A is declared.
3. All Interchange Transactions using Non-firm Point-to-Point Transmission Service are reallocated at 01:00.

Case 5. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 1 is called at 00:40.



1. Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 1.
2. All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled.
3. All Interchange Transactions using Non-firm Point-to-Point Transmission Service may be loaded immediately.

Appendix G. Examples of On-Path and Off-Path Mitigation

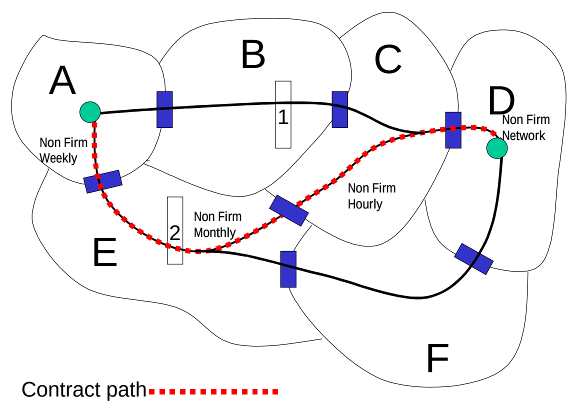
Examples

This section explains, by example, the obligations of the Transmission Service Providers on and off the Contract Path when calling for Transmission Loading Relief. (References to Principles refer to **Requirement 4, "Mitigating Constraints On and Off the Contract Path during TLR**," on the preceding pages.) When Reallocating or curtailing Interchange Transactions using Firm Point-to-Point Transmission Service under TLR Level 5a or 5b, the Transmission Service Providers may be obligated to perform comparable curtailments of its Transmission Service to Network Integration and Native Load customers. See **Requirement 5, "Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service during TLR**."

Scenario:

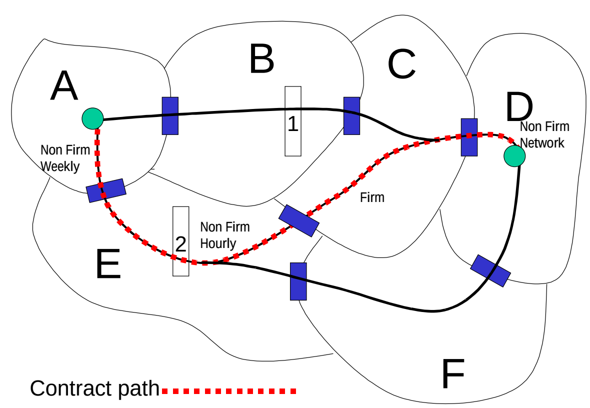
- Interchange Transaction arranged from system A to system D, and assumed to be at or above the Curtailment Threshold.
- Contract path is A-E-C-D (except as noted).
- Locations 1 and 2 denote Constraints.

Case 1: E is a non-firm Monthly path; C is non-firm Hourly; E has Constraint at #2



- E may call its Reliability Coordinator for TLR to relieve overload at Constraint #2.
- Interchange Transaction A-D may be curtailed by TLR action **as though it was being served by Non-firm Monthly Point-to-Point Transmission Service**, even though it was using Non-firm Hourly Point-to-Point Transmission Service from C. That is, it takes on the priority of the link with the Constrained Facility along the Contract Path (Principle 1).

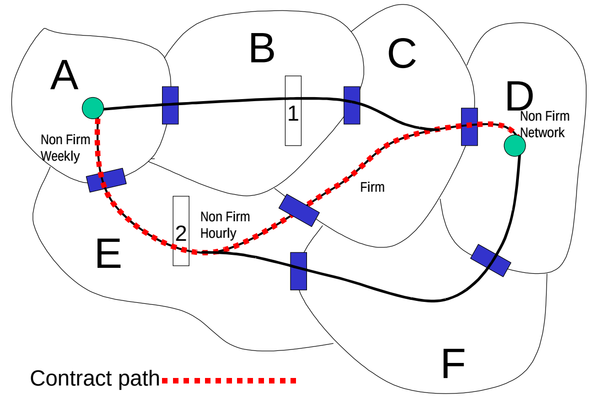
Case 2: E is a non-firm hourly path, C is firm; E has Constraint at #2



- Although C is providing Firm Service, the Constraint is not on C's system; therefore E is not obligated to treat the Interchange Transaction as though it was being served by Firm Point-to-Point Transmission Service.
- E may call its Reliability Coordinator for TLR to relieve overload at Constraint #2.
- Interchange Transaction A-D may be curtailed by TLR action as though it was being served by Non-firm Hourly Point-to-Point Transmission Service, even though it was using firm service from C. That is, when the constraint is on the Contract Path, the Interchange Transaction takes on the priority of the link with the Constrained Facility (Principle 1).

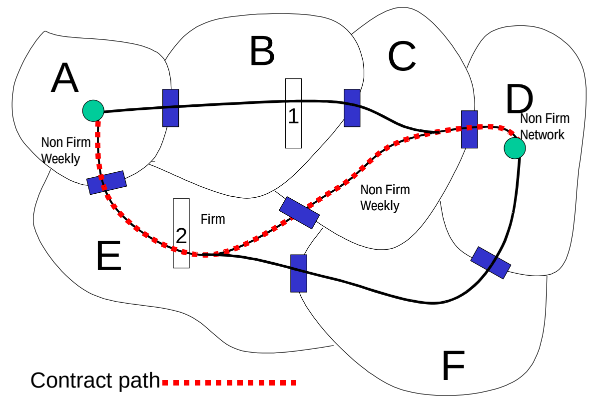
Case 3: E is a non-firm hourly path, C is firm, B has Constraint at #1

- B may call its Reliability Coordinator for TLR to relieve overload at Constraint #1.
- Interchange Transaction A-D may be curtailed by TLR action as though it was being served by Non-firm Hourly Transmission Service, even if it was using firm Transmission Service elsewhere on the path. When the constraint is off the Contract Path, the Interchange Transaction takes on the lowest priority reserved on the Contract Path (Principle 3).



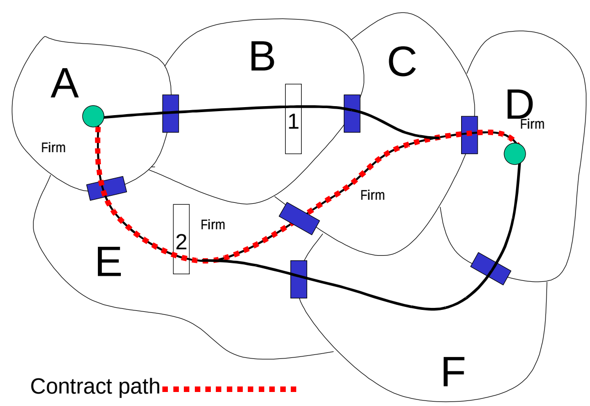
Case 4: E is a firm path; A, D, and C are Non-firm; E has Constraint at #2

- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may then call its Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-firm Point-to-Point Transmission Service first.
- E is obligated to try to reconfigure transmission to mitigate Constraint #2 in E before E may curtail the Interchange Transaction as ordered by the TLR (Principle 2).



Case 5: The entire path (A-E-C-D) is firm; E has Constraint at #2

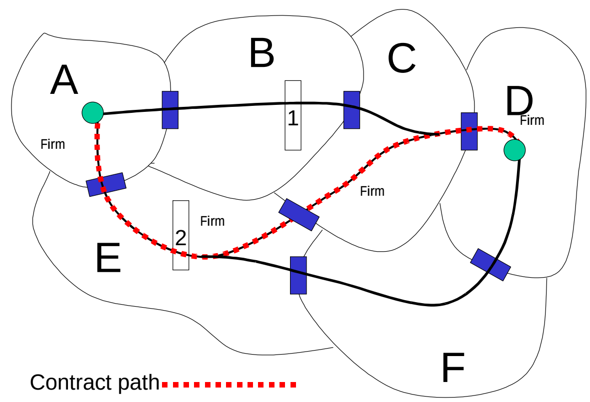
- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may call its Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-firm Point-to-Point Transmission Service first.
- E is obligated to curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service, and then reconfigure transmission on its system, or, if there is an agreement in place, arrange for reconfiguration or other congestion management options on another system, to mitigate Constraint #2 in E before the firm A-D transaction is curtailed (Principle 2).



- A, C, D, may be requested by E to try to reconfigure transmission to mitigate Constraint #2 in E at E's expense (Principle 2).

Case 6: The entire path (A-E-C-D) is firm; B has Constraint at #1.

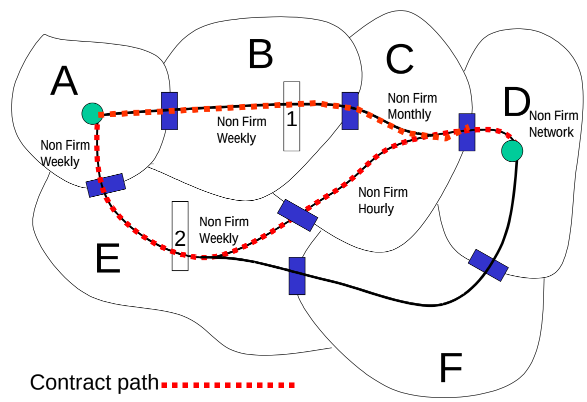
- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- B may call its Reliability Coordinator for TLR for all *non-firm* Interchange Transactions that contribute to the overload at Constraint #1.
- Following the curtailment of all non-firm Interchange Transactions, the Reliability Coordinator (ies) will determine which Transmission Operator(s) will reconfigure their transmission, if possible, to mitigate constraint #1 (Principle 4).



- A-D transaction may be curtailed as a result. However, the A-D transaction is treated as a firm Interchange Transaction and will be curtailed only after non-firm Interchange Transactions. (Note: This means that the firm Contract Path is respected by all parties, including those not on the Contract Path.) (Principle 4)

Case 7: Two A-to-D transactions using A-B-C-D and A-E-C-D; A and B are non-firm; B has Constraint at #1

- B is not obligated to reconfigure transmission to mitigate Constraint at #1. (Principle 1)
- B may call its Reliability Coordinator for TLR to relieve overload at Constraint #1.
- If both A – D Interchange Transactions have the same Transfer Distribution Factors across Constraint #1, then they both are subject to curtailment. However, Interchange Transaction A – D using the A-B-C-D path is assigned a higher priority (priority NW on B), and would not be curtailed until after the Interchange Transaction using the path A-E-C-D (priority NH on the Contract Path as observed by B who is off the Contract Path).



A. Introduction

1. **Title:** **Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators**

2. **Number:** **IRO-014-1**

3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** November 1, 2006

B. Requirements

R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators.

R1.1. These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:

R1.1.1. Communications and notifications, including the conditions[1] under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.

R1.1.2. Energy and capacity shortages.

R1.1.3. Planned or unplanned outage information.

R1.1.4. Voltage control, including the coordination of reactive resources for voltage control.

R1.1.5. Coordination of information exchange to support reliability assessments.

R1.1.6. Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.

R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be:

R2.1. Agreed to by all the Reliability Coordinators required to take the indicated action(s).

R2.2. Distributed to all Reliability Coordinators that are required to take the indicated action(s).

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[1] Examples of conditions when one Reliability Coordinator may need to notify another Reliability Coordinator may include (but aren't limited to) sabotage events, Interconnection Reliability Operating Limit violations, voltage reductions, insufficient resources, arming of special protection systems, etc.

R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include:

R3.1. A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

R3.2. The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

R4. Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:

R4.1. Include version control number or date.

R4.2. Include a distribution list.

R4.3. Be reviewed, at least once every three years, and updated if needed.

C. Measures

M1. The Reliability Coordinator's System Operators shall have available for Real-time use, the latest approved version of Operating Procedures, Processes, or Plans that require notifications, information exchange or the coordination of actions between Reliability Coordinators.

M1.1 These Operating Procedures, Processes, or Plans shall address:

M1.1.1 Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.

M1.1.2 Energy and capacity shortages.

M1.1.3 Planned or unplanned outage information.

M1.1.4 Voltage control, including the coordination of reactive resources for voltage control.

M1.1.5 Coordination of information exchange to support reliability assessments.

M1.1.6 Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.

M2. The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were:

M2.1 Agreed to by all the Reliability Coordinators required to take the indicated action(s).

M2.2 Distributed to all Reliability Coordinators that are required to take the indicated action(s).

M3. The Reliability Coordinator's Operating Procedures, Processes, or Plans developed (for its System Operators' internal use) to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan received from another Reliability Coordinator shall:

M3.1 Be available to the Reliability Coordinator's System Operators for Real-time use,

M3.2 Include a reference to the associated source document, and

M3.3 Support the agreed-upon actions from the source document.

M4. The Reliability Coordinator's Operating Procedures, Processes, or Plans that addresses Reliability Coordinator-to-Reliability Coordinator coordination shall each include a version control number or date and a distribution list. The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were reviewed within the last three years.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be one calendar year.

1.3. Data Retention

The Reliability Coordinator shall keep documentation for the prior calendar year and the current calendar year. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

1.4. Additional Compliance Information

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall also use a scheduled on-site review at least once every three years and investigations upon complaint. The Compliance Monitor shall conduct an investigation upon a complaint within 30 days of the alleged infraction's discovery date. The Compliance Monitor shall complete the investigation within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators to identify Operating Procedures, Processes or Plans that were distributed to the Reliability Coordinator being audited to verify that these documents are available for Real-time use by the receiving Reliability Coordinator's System Operators.

The Reliability Coordinator shall have the following documents available for inspection during an on-site audit or within five business days of a request as part of an investigation upon a complaint:

1.4.1 The latest version of its Operating Procedures, Processes, or Plans that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability.

1.4.2 Evidence of distribution of Operating Procedures, Processes, or Plans.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 The latest versions of Operating Procedures, Processes, or Plans (identified through self-certification) that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability do not include a version control number or date, and a distribution list.

2.1.2 The latest versions of Reliability Coordinator internal documents developed to support action(s) required as a result of other Reliability Coordinators do not include both a reference to the source Operating Procedure, Process, or Plan and the agreed-upon actions from the source Operating Procedure, Process, or Plan.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions is present:

2.2.1 Documents required by this standard were not distributed to all entities on the distribution list.

2.2.2 Documents required by this standard were not available for System Operators' Real-time use.

2.2.3 Documents required by this standard do not address all required topics.

2.3. Level 3: Documents required by this standard do not address any of the six required topics in Reliability Standard IRO-014 R1.

2.4. Level 4: Not Applicable.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	08/10/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Hyphenated "30-day" when used as adjective. 3. Changed standard header to be consistent with standard "Title." 4. Initial capped heading "Definitions of Terms Used in Standard." 5. Added "periods" to items where appropriate. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all words that are not "defined" terms — drafting team, self-certification. 8. Changed apostrophes to "smart" symbols. 9. Added comma in all word strings "Procedures, Processes, or Plans," etc. 10. Added hyphens to "Reliability Coordinator-to-Reliability Coordinator" where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate.	01/20/06

A. Introduction

1. **Title:** **Notifications and Information Exchange Between Reliability Coordinators**

2. **Number:** **IRO-015-1**

3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. **Applicability**

   4.1. Reliability Coordinators

5. **Effective Date:** November 1, 2006

B. Requirements

R1. The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators.

R1.1. The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.

R2. The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.

R2.1. The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.

R3. The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.

C. Measures

M1. The Reliability Coordinator shall have evidence (such as operator logs or other data sources) it has followed its Operating Procedures, Processes, or Plans for notifying other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.

M2. The Reliability Coordinator shall have evidence (such as operator logs or other data sources) that it participated in agreed upon (at least weekly) conference calls and other communication forums with adjacent Reliability Coordinators.

M3. The Reliability Coordinator shall have evidence that it provided requested reliability-related information to other Reliability Coordinators.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance Reset Period shall be one calendar year.

1.3. Data Retention

The Reliability Coordinator shall keep auditable documentation for a rolling 12 months. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance — whichever is longer.

1.4. Additional Compliance Information

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall also use a scheduled on-site review at least once every three years and investigations upon complaint. The Compliance Monitor shall conduct an investigation upon a complaint within 30 days of the alleged infraction's discovery date. The Compliance Monitor shall complete the investigation within 45 days after the start of the investigation. As part of an audit or an investigation, the Compliance Monitor shall interview other Reliability Coordinators within the Interconnection and verify that the Reliability Coordinator being audited or investigated has been making notifications and exchanging reliability-related information according to agreed Operating Procedures, Processes, or Plans.

The Reliability Coordinator shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within five days of a request as part of an investigation upon complaint:

1.4.1 Evidence it has participated in agreed-upon conference calls or other communications forums.

1.4.2 Operating logs or other data sources that document notifications made to other Reliability Coordinators.

2. Levels of Non-Compliance

2.1. Level 1: Did not participate in agreed upon (at least weekly) conference calls and other communication forums with adjacent Reliability Coordinators.

2.2. Level 2: Did not notify other Reliability Coordinators as specified in its Operating Procedures, Processes, or Plans for making notifications but no Adverse Reliability Impacts resulted from the incident.

2.3. Level 3: Did not provide requested reliability-related information to other Reliability Coordinators.

2.4. Level 4: Did not notify other Reliability Coordinators as specified in its Operating Procedures, Processes, or Plans for making notifications and Adverse Reliability Impacts resulted from the incident.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	08/10/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)."	01/20/06

		2. Hyphenated “30-day” and reliability-related when used as adjective. 3. Changed standard header to be consistent with standard “Title.” 4. Added “periods” to items where appropriate. 5. Initial capped heading “Definitions of Terms Used in Standard.” 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all words that are not “defined” terms — drafting team, and self-certification. 8. Changed apostrophes to “smart” symbols. 9. Added comma in all word strings “Procedures, Processes, or Plans,” etc. 10. Added hyphens to “Reliability Coordinator-to-Reliability Coordinator” where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate.	

A. Introduction

1. **Title:** **Coordination of Real-time Activities Between Reliability Coordinators**

2. **Number:** **IRO-016-1**

3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. **Applicability**

    4.1. Reliability Coordinator

5. **Effective Date:** November 1, 2006

B. Requirements

R1. The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.

R1.1. If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken.

R1.2. If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).

R1.2.1. If time permits, this re-evaluation shall be done before taking corrective actions.

R1.2.2. If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.

R1.3. If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.

R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.

C. Measures

M1. For each event that requires Reliability Coordinator-to-Reliability Coordinator coordination, each involved Reliability Coordinator shall have evidence (operator logs or other data sources) of the actions taken for either the event or for the disagreement on the problem or for both.

D. Compliance

1. **Compliance Monitoring Process**

    1.1. Compliance Monitoring Responsibility

    Regional Reliability Organization

    1.2. Compliance Monitoring Period and Reset Time Frame

    The performance reset period shall be one calendar year.

1.3. Data Retention

The Reliability Coordinator shall keep auditable evidence for a rolling 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until it has been found compliant. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

1.4. Additional Compliance Information

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall use a scheduled on-site review at least once every three years. The Compliance Monitor shall conduct an investigation upon a complaint that is received within 30 days of an alleged infraction's discovery date. The Compliance Monitor shall complete the investigation and report back to all involved Reliability Coordinators (the Reliability Coordinator that complained as well as the Reliability Coordinator that was investigated) within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators within the Interconnection and verify that the Reliability Coordinator being audited or investigated has been coordinating actions to prevent or resolve potential, expected, or actual problems that adversely impact the Interconnection.

The Reliability Coordinator shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within five working days of a request as part of an investigation upon complaint:

1.4.1 Evidence (operator log or other data source) to show coordination with other Reliability Coordinators.

2. Levels of Non-Compliance

2.1. Level 1: For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did coordinate, but did not have evidence that it coordinated with other Reliability Coordinators.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did not coordinate with other Reliability Coordinators.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	August 10, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Hyphenated "30-day" and "Reliability Coordinator-to-Reliability Coordinator" when used as adjective.	01/20/06

		3. Changed standard header to be consistent with standard "Title." 4. Added "periods" to items where appropriate. 5. Initial capped heading "Definitions of Terms Used in Standard." 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all words that are not "defined" terms — drafting team, and self-certification. 8. Changed apostrophes to "smart" symbols. 9. Removed comma after word "condition" in item R.1.1. 10. Added comma after word "expected" in item 1.4, last sentence. 11. Removed extra spaces between words where appropriate.	

Introduction

1. **Title:** **Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies**
2. **Number:** MOD-001-0
3. **Purpose:** To promote the consistent and uniform application of Transfer Capability calculations among transmission system users, the Regional Reliability Organization shall develop methodologies for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that comply with NERC definitions for TTC and ATC, NERC Reliability Standards, and applicable Regional criteria.
4. **Applicability:**
   - **4.1.** Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional TTC and ATC methodology. (Certain systems that are not required to post ATC values are exempt from this standard.) The Regional Reliability Organization's TTC and ATC methodology shall include each of the following nine items, and shall explain its use in determining TTC and ATC values:

R1.1. A narrative explaining how TTC and ATC values are determined.

R1.2. An accounting for how the reservations and schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the Transmission Service Provider's system, are included.

R1.3. An accounting for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations.

R1.4. A description of how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or because the reservations have not all been made.)

R1.5. A requirement that TTC and ATC values shall be determined and posted as follows:

R5.1.1. Daily values for current week at least once per day.

R5.1.2. Daily values for day 8 through the first month at least once per week.

R5.1.3. Monthly values for months 2 through 13 at least once per month.

R1.6. Indication of the treatment and level of customer demands, including interruptible demands.

R1.7. A specification of how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by Transmission Service Providers for the calculation of TTC and ATC values are shared and used within the Regional Reliability Organization and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regional Reliability

Organizations. In addition, specify how this information is to be used to determine TTC and ATC values. If some data is not used, provide an explanation.

R1.8. A description of how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons.

R1.9. A description of the Regional Reliability Organization's practice on the netting of transmission reservations for purposes of TTC and ATC determination.

R2. The Regional Reliability Organization shall make the most recent version of the documentation of its TTC and ATC methodology available on a web site accessible by NERC, the Regional Reliability Organizations, and transmission users.

C. Measures

M1. The Regional Reliability Organization shall provide evidence that its most recent TTC and ATC methodology documentation meets Reliability Standard MOD-001-0_R1.

M2. The Regional Reliability Organization shall provide evidence that its TTC and ATC methodology is available on a web site accessible by NERC, the Regional Reliability Organizations, and transmission users.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.

1.3. Data Retention

None identified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's documented TTC and ATC methodology does not address one or two of the nine items required for documentation under Reliability Standard MOD-001-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's documented TTC and ATC methodology does not address three or more of the nine items required for documentation under Reliability Standard MOD-001-0_R1 or the Regional Reliability Organization does not have a documented TTC and ATC methodology available on a web site in accordance with Reliability Standard MOD-001-0_R2.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Review of Transmission Service Provider Total Transfer Capability and Available Transfer Capability Calculations and Results**
2. **Number:** MOD-002-0
3. **Purpose:** To promote the consistent and uniform application of transfer capability calculations among Transmission Service Providers, the Regional Reliability Organizations need to review adherence to Regional methodologies for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC).
4. **Applicability:**
   4.1. Regional Reliability Organizations
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to periodically review (at least annually) and ensure that the TTC and ATC calculations and resulting values of member Transmission Service Providers comply with the Regional TTC and ATC methodology and applicable Regional criteria.

R2. Each Regional Reliability Organization shall document the results of its periodic reviews of TTC and ATC.

R3. The Regional Reliability Organization shall provide the results of its most current reviews of TTC and ATC to NERC on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization's written procedure for the performance of periodic reviews of Regional TTC and ATC calculations shall comply with Reliability Standard MOD-002-0_R1.

M2. The Regional Reliability Organization shall have evidence that it provided documentation of the results of its periodic reviews of TTC and ATC to NERC within 30 calendar days.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Procedure on Request (within 30 calendar days).

   Documentation provided by NERC on request (within 30 calendar days).

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: The Regional Reliability Organization did not perform an annual review of all Transmission Service Providers within its Region for consistency with its TTC and ATC methodology.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization does not have a procedure for performing a TTC and ATC methodology consistency review of all Transmission Service Providers within its Regional Reliability Organization, or has not performed such annual reviews.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**

2. **Number:** MOD-003-0

3. **Purpose:** To promote the consistent and uniform application of Transfer Capability calculations among Transmission Service Providers, the Regional Reliability Organizations need to review adherence to Regional methodologies for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC).

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a procedure on how transmission users can input their concerns or questions regarding the TTC and ATC methodology and values of the Transmission Service Provider(s), and how these concerns or questions will be addressed. The Regional Reliability Organization's procedure shall specify the following:

R1.1. The name, telephone number and email address of a contact person to whom concerns are to be addressed.

R1.2. The amount of time it will take for a response.

R1.3. The manner in which the response will be communicated (e.g., email, letter, telephone, etc).

R1.4. What recourse a customer has if the response is deemed unsatisfactory.

R2. The Regional Reliability Organization shall post on a web site that is accessible by the Regional Reliability Organizations, NERC, and transmission users, its procedure for receiving and addressing concerns about the TTC and ATC methodology and TTC and ATC values of member Transmission Service Providers.

C. Measures

M1. The Regional Reliability Organization shall have evidence that its procedure for receiving input for ATC and TTC methodologies and values meets Reliability Standard MOD-003-0_R1.

M2. The Regional Reliability Organization shall have evidence that its procedure for receiving input for ATC and TTC methodologies and values is available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Procedure available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: The Regional Reliability Organization does not have a procedure available on an accessible web site, or the procedure does not incorporate all required elements of Reliability Standard MOD-003-0_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization has no procedure available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Documentation of Regional Reliability Organization Capacity Benefit Margin Methodologies**

2. **Number:** MOD-004-0

3. **Purpose:** To promote the consistent and uniform application of transmission Transfer Capability margins calculations, Capacity Benefit Margin (CBM) must be calculated in a consistent manner.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional CBM methodology. The Regional Reliability Organization's CBM methodology shall include each of the following ten items, and shall explain its use in determining CBM value. Other items that are Regional Reliability Organization specific or that are considered in each respective Regional Reliability Organization methodology shall also be explained along with their use in determining CBM values.

R1.1. Specify that the method used by each Regional Reliability Organization member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria.

R1.2. Specify the frequency of calculation of the generation reliability requirement and associated CBM values.

R1.3. Require that generation unit outages considered in a Transmission Service Provider's CBM calculation be restricted to those units within the Transmission Service Provider's system.

R1.4. Require that CBM be preserved only on the Transmission Service Provider's System where the Load-Serving Entity's Load is located (i.e., CBM is an import quantity only).

R1.5. Describe the inclusion or exclusion rationale for generation resources of each Load-Serving Entity including those generation resources not directly connected to the Transmission Service Provider's system but serving Load-Serving Entity loads connected to the Transmission Service Provider's system.

R1.6. Describe the inclusion or exclusion rationale for generation connected to the Transmission Service Provider's system but not obligated to serve Native/Network Load connected to the Transmission Service Provider's system.

R1.7. Describe the formal process and rationale for the Regional Reliability Organization to grant any variances to individual Transmission Service Providers from the Regional Reliability Organization's CBM methodology.

R1.8. Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the

CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.

R1.9. Describe the inclusion or exclusion rationale for the loads of each Load-Serving Entity, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions).

R1.10. Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the CBM values.

R2. The Regional Reliability Organization shall make the most recent version of the documentation of its CBM methodology available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.

C. Measures

M1. The Regional Reliability Organization's most recent CBM methodology documentation shall meet Reliability Standard MOD-004-0_R1.

M2. The Regional Reliability Organization's CBM methodology shall be available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

The most recent version of CBM methodology documentation available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's documented CBM methodology does not address one or two of the ten items required for documentation under Reliability Standard MOD-004-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's documented CBM methodology does not address three or more of the ten items required for documentation under Reliability Standard MOD-004-0_R1, or the Regional Reliability Organization does not have a documented CBM methodology available on a website in accordance with Reliability Standard MOD-004-0_R2.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Procedure for Verifying Capacity Benefit Margin Values**
2. **Number:** MOD-005-0
3. **Purpose:** To promote the consistent and uniform application of Transfer Capability calculations among transmission system users, the Regional Reliability Organizations need to review adherence to Regional methodologies for calculating Capacity Benefit Margin (CBM).
4. **Applicability:**
    4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review (at least annually) the CBM calculations and the resulting values of member Transmission Service Providers to ensure that they comply with the Regional Reliability Organization's CBM methodology. The procedure shall include the following four requirements:

R1.1. Indicate the frequency under which the verification review shall be implemented.

R1.2. Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to transmission users.

R1.3. Require review of the consistency of the Transmission Service Provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the components that comprise CBM are addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained.

R1.4. Require CBM values to be periodically updated (at least annually) and available to the Regional Reliability Organizations, NERC, and transmission users.

R2. Each Regional Reliability Organization shall document its CBM procedure and shall make its CBM review procedure available to NERC on request (within 30 calendar days).

R3. The Regional Reliability Organization shall provide documentation of the results of the most current implementation of its CBM review procedure to NERC on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization's written procedure for the performance of periodic reviews of Regional CBM calculations shall comply with Reliability Standard MOD-005_R1.

M2. The Regional Reliability Organization shall have documentation of the results of its periodic reviews of CBM calculations, in accordance with Reliability Standard MOD-005-0_R2 and MOD-005-0_R3.

M3. The Regional Reliability Organization shall have evidence that it provided documentation of its CBM review procedure and the results of the most current implementation of the procedure to NERC as requested (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

The documentation of the Regional Reliability Organization's CBM review procedure shall be available to NERC on request (within 30 calendar days). Documentation of the results of the most current implementation of the review procedure shall be available to NERC on request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: The Regional Reliability Organization did not perform an annual review of all Transmission Service Providers within its Region for consistency with the Regional CBM methodology.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization does not have a procedure for performing a CBM methodology consistency review of all Transmission Service Providers within its Region, or has not performed any annual reviews.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Procedures for the Use of Capacity Benefit Margin Values**

2. **Number:** MOD-006-0

3. **Purpose:** To promote the consistent and uniform use of transmission Transfer Capability margins calculations among transmission system users,

4. **Applicability:**

   4.1. Transmission Service Provider

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Service Provider shall document its procedure on the use of Capacity Benefit Margin (CBM) (scheduling of energy against a CBM preservation). The procedure shall include the following three components:

R1.1. Require that CBM be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, Direct-Control Load Management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish Operating Reserves.

R1.2. Require that CBM shall only be used if the Load-Serving Entity calling for its use is experiencing a generation deficiency and its Transmission Service Provider is also experiencing Transmission Constraints relative to imports of energy on its transmission system.

R1.3. Describe the conditions under which CBM may be available as Non-Firm Transmission Service.

R2. Each Transmission Service Provider shall make its CBM use procedure available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users..

C. Measures

M1. The Transmission Service Provider's procedure for the use of CBM (scheduling of energy against a CBM preservation) shall meet Reliability Standard MOD-006-0_R1.

M2. The Transmission Service Provider's procedure for the use of CBM (scheduling of energy against a CBM preservation) shall be available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations

   1.2. Compliance Monitoring Period and Reset Timeframe

   Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC compliance reporting process.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Service Provider's procedure for use of CBM is available and addresses only two of the three requirements for such documentation as listed above under Reliability Standard MOD-006-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Transmission Service Provider's procedure for use of CBM addresses one or none of the three requirements as listed above under Reliability Standard MOD-006-0_R1, or is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Documentation of the Use of Capacity Benefit Margin**

2. **Number:** MOD-007-0

3. **Purpose:** To promote the consistent and uniform application of Transfer Capability margin calculations among transmission system users by developing methodologies for calculating Capacity Benefit Margin (CBM). This methodology shall comply with NERC definitions for CBM, the NERC Reliability Standards, and applicable Regional criteria.

4. **Applicability:**

   4.1. Transmission Service Provider

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Service Provider that uses CBM shall report (to the Regional Reliability Organization, NERC and the transmission users) the use of CBM by the Load-Serving Entities' Loads on its system, except for CBM sales as Non-Firm Transmission Service. (This use of CBM shall be consistent with the Transmission Service Provider's procedure for use of CBM.)

R2. The Transmission Service Provider shall post the following three items within 15 calendar days after the use of CBM for an Energy Emergency. This posting shall be on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.

R2.1. Circumstances.

R2.2. Duration.

R2.3. Amount of CBM used.

C. Measures

M1. The Transmission Service Provider shall have evidence that it posted an after-the-fact disclosure that energy was scheduled against a CBM preservation (for purposes other than Non-Firm Transmission Sales) on a website accessible by the Regional Reliability Organizations, NERC, and transmission users.

M2. If the Transmission Service Provider had energy scheduled against a CBM preservation (for purposes other than Non-Firm Transmission Sales) the Transmission Service Provider shall have evidence it posted an after-the-fact disclosure that includes the elements required by Reliability Standard MOD-007_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Within 15 calendar days of the use of CBM (excluding Non-Firm Transmission Sales)

   1.3. Data Retention

   None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Information pertaining to the use of CBM during an Energy Emergency was provided, but was not made available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users, or meets only two of the three requirements as listed in Reliability Standard MOD-007-0_R2.

2.3. Level 3: Not applicable.

2.4. Level 4: After the use of CBM (excluding Non-Firm Transmission Sales), information pertaining to the use of CBM was provided but meets one or none of the three requirements as listed above under Reliability Standard MOD-007-0_R2, or no information was provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title: Documentation and Content of Each Regional Transmission Reliability Margin Methodology**

2. **Number:** MOD-008-0

3. **Purpose:** To promote the consistent application of transmission Transfer Capability margin calculations among Transmission Service Providers and Transmission Owners, each Regional Reliability Organization shall develop a methodology for calculating Transmission Reliability Margin (TRM). This methodology shall comply with the NERC definition for TRM, the NERC Reliability Standards, and applicable Regional criteria.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional TRM methodology. The Region's TRM methodology shall specify or describe each of the following five items, and shall explain its use, if any, in determining TRM values. Other items that are Region-specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining TRM values.

R1.1. Specify the update frequency of TRM calculations.

R1.2. Specify how TRM values are incorporated into Available Transfer Capability calculations.

R1.3. Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. Any component of uncertainty, other than those identified in MOD-008-0_R1.3.1 through MOD-008-0_R1.3.7, shall benefit the interconnected transmission systems as a whole before they shall be permitted to be included in TRM calculations. The components of uncertainty identified in MOD-008-0_R1.3.1 through MOD-008-0_R1.3.7, if applied, shall be accounted for solely in TRM and not CBM.

R1.3.1. Aggregate Load forecast error (not included in determining generation reliability requirements).

R1.3.2. Load distribution error.

R1.3.3. Variations in facility Loadings due to balancing of generation within a Balancing Authority Area.

R1.3.4. Forecast uncertainty in transmission system topology.

R1.3.5. Allowances for parallel path (loop flow) impacts.

R1.3.6. Allowances for simultaneous path interactions.

R1.3.7. Variations in generation dispatch.

R1.3.8. Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).

R1.4. Describe the conditions, if any, under which TRM may be available to the market as Non-Firm Transmission Service.

R1.5. Describe the formal process for the Regional Reliability Organization to grant any variances to individual Transmission Service Providers from the Regional TRM methodology.

R2. The Regional Reliability Organization shall make its most recent version of the documentation of its TRM methodology available on a web site accessible by NERC, the Regional Reliability Organizations, and transmission users.

C. Measures

M1. The Regional Reliability Organization's most recent version of the documentation of its TRM methodology is available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.

M2. The Regional Reliability Organization's most recent version of the documentation of its TRM contains all items in Reliability Standard MOD-008-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's documented TRM methodology does not address one of the five items required for documentation under Reliability Standard MOD-008-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's documented TRM methodology does not address two or more of the five items required for documentation under Reliability Standard MOD-008-0_R1.

Or

The Regional Reliability Organization does not have a documented TRM methodology.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Procedure for Verifying Transmission Reliability Margin Values**

2. **Number:** MOD-009-0

3. **Purpose:** To promote the consistent application of transmission Transfer Capability margin calculations among Transmission System Providers and Transmission Owners.

4. **Applicability:**

    4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review Transmission Reliability Margin (TRM) calculations and resulting values of member Transmission Service Providers to ensure they comply with the Regional TRM methodology, and are periodically updated and available to transmission users. This procedure shall include the following four required elements:

R1.1. Indicate the frequency under which the verification review shall be implemented.

R1.2. Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to transmission users.

R1.3. Require review of the consistency of the Transmission Service Provider's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained.

R1.4. Require TRM values to be periodically updated (at least prior to each season — winter, spring, summer, and fall), as necessary, and made available to the Regional Reliability Organizations, NERC, and transmission users.

R2. The Regional Reliability Organization shall make documentation of its Regional TRM review procedure available to NERC on request (within 30 calendar days).

R3. The Regional Reliability Organization shall make documentation of the results of the most current implementation of its TRM review procedure available to NERC on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization shall have evidence that it provided to NERC upon request (within 30 calendar days) a copy of its written procedure developed for the performance of periodic reviews of Regional TRM calculations.

M2. The Regional Reliability Organization shall have evidence it provided to NERC on request (within 30 calendar days) documentation of the results of the most current implementation of its TRM review procedure.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: The Regional Reliability Organization did not perform an annual review of all Transmission Service Providers within its Region for consistency with its Regional TRM methodology.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization does not have a procedure for performing a TRM methodology consistency review of all Transmission Service Providers within its Region, or has not performed any such annual reviews.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Steady-State Data for Modeling and Simulation of the Interconnected Transmission System**

2. **Number:** MOD-010-0

3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Interconnected Transmission Systems.

4. **Applicability:**

   4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-011-0_R1

   4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

   4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-011-0_R1

   4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owners, Transmission Planners Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.

R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).

C. Measures

M1. The Transmission Owner, Transmission Planner, Generator Owner, and Resource Planner, (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall have evidence that it provided equipment characteristics, system data, and Interchange Schedules for steady-state modeling and simulation to the Regional Reliability Organizations and NERC as specified in Standard MOD-010-0_R1 and MOD-010-0_R2.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations.

   1.2. Compliance Monitoring Period and Reset Timeframe

As specified within the applicable reporting procedures (Reliability Standard MOD-011-0_R2-M1). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Steady-state data was provided, but was incomplete in one of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Steady-state data was provided, but was incomplete in two or more of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.4. Level 4: Steady-state data was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures.**

2. **Number:** MOD-011-0

3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Regional Reliability Organizations within an Interconnection, in conjunction with the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate the development of the data requirements and reporting procedures for that Interconnection. The Interconnection-wide requirements shall include the following steady-state data requirements:

R1.1. Bus (substation): name, nominal voltage, electrical demand supplied (consistent with the aggregated and dispersed substation demand data supplied per Reliability Standards MOD-016-0, MOD-017-0, and MOD-020-0), and location.

R1.2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status.

R1.3. AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0) equipment status, and metering locations.

R1.4. DC Transmission Line (overhead and underground): line parameters, Normal and Emergency Ratings, control parameters, rectifier data, and inverter data.

R1.5. Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0.), and equipment status.

R1.6. Reactive Compensation (shunt and series capacitors and reactors): nominal Ratings, impedance, percent compensation, connection point, and controller device.

R1.7. Interchange Schedules: Existing and future Interchange Schedules and/or assumptions.

R2. The Regional Reliability Organizations within an Interconnection shall document their Interconnection's steady-state data requirements and reporting procedures, shall review those data requirements and reporting procedures (at least every five years), and shall make the data requirements and reporting procedures available on request (within five business days) to Regional Reliability Organizations, NERC, and all users of the interconnected transmission systems.

C. Measures

M1. The Regional Reliability Organization shall have documentation of its Interconnection's steady-state data requirements and reporting procedures and shall provide the documentation as specified in Reliability Standard MOD-011-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Periodic review of data requirements and reporting procedures: at least every five years.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Data requirements and reporting procedures for steady-state data were provided, but were incomplete in one of the seven areas defined in Reliability Standard MOD-011-0_R1.

2.2. Level 2: Data requirements and reporting procedures for steady-state data were provided, but were incomplete in two of the seven areas defined in Reliability Standard MOD-011-0_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: Data requirements and reporting procedures for steady-state data were not provided, or the data requirements and reporting procedures provided were incomplete in three or more of the seven areas defined in Reliability Standard MOD-011-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Dynamics Data for Modeling and Simulation of the Interconnected Transmission System.**
2. **Number:** MOD-012-0
3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.
4. **Applicability:**
   - **4.1.** Transmission Owners specified in the data requirements and reporting procedures of MOD-013-0_R1
   - **4.2.** Transmission Planners specified in the data requirements and reporting procedures of MOD-013-0_R1
   - **4.3.** Generator Owners specified in the data requirements and reporting procedures of MOD-013-0_R1
   - **4.4.** Resource Planners specified in the data requirements and reporting procedures of MOD-013-0_R1
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.

R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R1. If no schedule exists, then these entities shall provide data on request (30 calendar days).

C. Measures

M1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall each have evidence that it provided equipment characteristics and system data for dynamics system modeling and simulation in accordance with Reliability Standard MOD-012-0_R1 and Reliability Standard MOD-012-0_R2.

D. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance Monitoring Responsibility**

     Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

As specified within the applicable reporting procedures (Reliability Standard MOD-013-0). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Dynamics data was provided, but was incomplete in one of the four areas identified in Reliability Standard MOD-013-0_R1.

2.2. Level 2: Not Applicable.

2.3. Level 3: Dynamics data was provided, but was incomplete in two or more of the four areas identified in Reliability Standard MOD-013-0_R1.

2.4. Level 4: Dynamics data was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	September 16, 2005	Changed references to MOD-013-0 R4 to MOD-013-0 R1 in Applicability, Requirements, and Measures (4 in all).	Errata

A. Introduction

1. **Title:** **Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures**

2. **Number:** MOD-013-0

3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Regional Reliability Organization, in coordination with its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. Each set of Interconnection-wide dynamics data requirements shall include the following dynamics data requirements::

R1.1. Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment.

R1.1.1. Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.

R1.1.2. The Interconnection-wide requirements shall specify unit size thresholds for permitting:

- The use of non-detailed vs. detailed models,
- The netting of small generating units with bus load, and
- The combining of multiple generating units at one plant.

R1.2. Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, and static compensators.

R1.3. Dynamics data representing electrical demand characteristics as a function of frequency and voltage.

R1.4. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard MOD-010-0_R1.

R2. The Regional Reliability Organization shall participate in the documentation of its Interconnection's data requirements and reporting procedures and, shall participate in the review of those data requirements and reporting procedures (at least every five years), and shall provide those data requirements and reporting procedures to Regional Reliability Organizations, NERC, and all users of the Interconnected systems on request (within five business days).

C. Measures

M1. The Regional Reliability Organizations within each Interconnection shall have documentation of their Interconnection's dynamics data requirements and reporting procedures and shall provide the documentation as specified in Reliability Standard MOD-013-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Data requirements and reporting procedures: on request (5 business days).

Periodic review of data requirements and reporting procedures: at least every five years.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Data requirements and reporting procedures for dynamics data were provided, but were incomplete in one of the four areas defined in Reliability Standard MOD-013-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Data requirements and reporting procedures for dynamics data were not provided, or the data requirements and reporting procedures provided were incomplete in two or more of the four areas defined in Reliability Standard MOD-013-0_R1.

E. Regional Differences

1. None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Development of Steady-State System Models**

2. **Number:** MOD-014-0

3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of solved (converged) Interconnection-specific steady-state system models. The Interconnection-specific models shall include near- and longer-term planning horizons that are representative of system conditions for projected seasonal peak, minimum, and other appropriate system demand levels.

R2. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop steady-state system models annually for selected study years, as determined by the Regional Reliability Organizations within its Interconnection. The Regional Reliability Organization shall provide the most recent solved (converged) Interconnection-specific steady-state models to NERC in accordance with each Interconnection's schedule for submission.

C. Measures

M1. Each Regional Reliability Organization shall have Interconnection-specific steady-state system models as specified in MOD-014-0_R1 and MOD-014-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Development of steady-state system models: annually, as determined by each Interconnection's schedule.

   Most recent steady-state system models: 30 calendar days.

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. Levels of Non-Compliance

2.1. Level 1: One of a Regional Reliability Organization's cases either was not submitted by each Interconnection's data submission deadlines, or was submitted by the data submission deadline but was not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.

2.2. Level 2: Two of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

2.3. Level 3: Three of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

2.4. Level 4: Four or more of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Development of Dynamics System Models**

2. **Number:** MOD-015-0

3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of initialized (with no Faults or system Disturbances) Interconnection-specific dynamics system models linked to the steady-state system models, as appropriate, of Reliability Standard MOD-014-0_R1.

R1.1. The Regional Reliability Organization(s) shall develop Interconnection-specific dynamics system models for at least two timeframes (present or near-term model and a future or longer-term model), and additional seasonal and demand level models, as necessary, to analyze the dynamic response of that Interconnection.

R2. The Regional Reliability Organization(s) within each Interconnection shall develop Interconnection dynamics system models for their Interconnection annually for selected study years as determined by the Regional Reliability Organization(s) within each Interconnection and shall provide the most recent initialized (approximately 25 seconds, no-fault) models to NERC in accordance with each Interconnection's schedule for submission.

C. Measures

M1. The Regional Reliability Organization shall have Interconnection-specific dynamics system models in accordance with Reliability Standard MOD-015-0_R1, MOD-015-0_R2 and MOD-015-0_R3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Development of dynamics system models: annually in accordance with each Interconnection's schedule.

   Most recent dynamics system models: 30 calendar days.

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. Levels of Non-Compliance

2.1. Level 1: One of a Regional Reliability Organization's cases was either not submitted by each Interconnection's data submission deadlines, or was submitted by the data submission deadline but was not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.

2.2. Level 2: Two of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

2.3. Level 3: Three of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

2.4. Level 4: Four or more of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

E. Regional Differences

1. None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management**

2. **Number:** MOD-016-0

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management (DSM) programs is needed.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.

R1.1. The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005-0, TPL-006-0, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-0, MOD-014-0, MOD-015-0, MOD-016, MOD-017-0, MOD-018-0, MOD-019-0, MOD-020-0, and MOD-021-0.

R2. The documentation of the scope and details of the data reporting requirements shall be available on request (five business days).

C. Measures

M1. The Planning Authority and Regional Reliability Organization shall each provide evidence to its Compliance Monitor that it provided data and reporting procedures per Reliability Standard MOD-016-0_R1 and MOD-016-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor for Planning Authority: Regional Reliability Organization.
   Compliance Monitor for Regional Reliability Organization: NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (five business days.)

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

   2.1. **Level 1:** Identified the scope and details of demand, Net Energy for Load, and controllable DSM data to be reported and the reporting procedures but did not specify that consistent data is to be supplied for Reliability Standards TPL-005-0, TPL-006-0, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-0, MOD-014-0, MOD-015-0, MOD-016, MOD-017-0, MOD-018-0, MOD-019-0, MOD-020-0, and MOD-021-0.

   2.2. **Level 2:** Not applicable.

   2.3. **Level 3:** Not applicable.

   2.4. **Level 4:** Did not identify the scope and details of demand, Net Energy for Load, and controllable DSM data to be reported and the reporting procedures.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Aggregated Actual and Forecast Demands and Net Energy for Load**

2. **Number:** MOD-017-0

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual Demand data is needed. Forecast demand data is needed to perform future system assessment to identify the need for system reinforcement for continued reliability. In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Planning Authority

   4.3. Resource Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-0_R1.

R1.1. Integrated hourly demands in megawatts (MW) for the prior year.

R1.2. Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.

R1.3. Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.

R1.4. Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the future, as requested.

C. Measures

M1. Load-Serving Entity, Planning Authority, and Resource Planner shall each provide evidence to its Compliance Monitor that it provided load data per Standard MOD-017-0_R1.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Annually or as specified in the documentation (Standard MOD-016-0_R1.)

   1.3. Data Retention

   None specified.

1.4. Additional Compliance Information
None.

2. Levels of Non-Compliance

2.1. Level 1: Did not provide actual and forecast demands and Net Energy for Load data in one of the four areas as required in Reliability Standard MOD-017-0_R1.

2.2. Level 2: Did not provide actual and forecast demands and Net Energy for Load data in two of the four areas as required in Reliability Standard MOD-017-0_R1.

2.3. Level 3: Did not provide actual and forecast demands and Net Energy for Load data in three of the four areas as required in Reliability Standard MOD-017-0_R1.

2.4. Level 4: Did not provide actual and forecast demands and Net Energy for Load data in any of the areas as required in Reliability Standard MOD-017-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load**

2. **Number:** MOD-018-0

3. **Purpose:** To ensure that Assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Resource Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast demand data (reported on either an aggregated or dispersed basis) shall:

R1.1. Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and

R1.2. Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load.

R1.3. Items (MOD-018-0_R1.1) and (MOD-018-0_R1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-0_R1.

R2. The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner shall each report data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days).

C. Measures

M1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide evidence to its Compliance Monitor that its actual and forecast demand data were addressed as described in the reporting procedures developed for Reliability Standard MOD-018-0_R1.

M2. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each report current information for Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Monitoring Responsibility**

   Regional Reliability Organizations.

   1.2. **Compliance Monitoring Period and Reset Timeframe**

   On Request (within 30 calendar days).

   1.3. **Data Retention**

   None specified.

   1.4. **Additional Compliance Information**

   None.

2. **Levels of Non-Compliance**

   2.1. **Level 1:** Information for Reliability Standard MOD-018-0 item R1.1 or R1.2 was not provided.

   2.2. **Level 2:** Information for Reliability Standards MOD-018-0 items R1.1 and R1.2 was not provided.

   2.3. **Level 3:** Not applicable.

   2.4. **Level 4:** Not applicable.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Reporting of Interruptible Demands and Direct Control Load Management**

2. **Number:** MOD-019-0

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Planning Authority

   4.3. Transmission Planner

   4.4. Resource Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-0_R1**.**

C. Measures

M1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide evidence to its Compliance Monitor that it provided forecasts of interruptible demands and DCLM data per Reliability Standard MOD-019-0_R1.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Each Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Annually or as specified in the documentation (Reliability Standard MOD-016-0_R1.)

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

   2.1. Level 1: Not applicable.

   2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Did not provide forecasts of interruptible Demands and DCLM data as required in Standard MOD-019-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators**

2. **Number:** MOD-020-0

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Transmission Planner

   4.3. Resource Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load Management (DCLM) to Transmission Operators, Balancing Authorities, and Reliability Coordinators on request within 30 calendar days.

C. Measures

M1. The Load-Serving Entity, Transmission Planner, and Resource Planner each make known its amount of interruptible demands and DCLM to Transmission Operators, Balancing Authorities and Reliability Coordinators on request within 30 calendar days.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (within 30 calendar days).

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

   2.1. Level 1: Interruptible Demands and DCLM data were provided to Reliability Coordinators, Balancing Authorities, and Transmission Operators, but were incomplete.

   2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Interruptible Demands and DCLM data were not provided to Reliability Coordinators, Balancing Authorities, and Transmission Operators.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title: Documentation of the Accounting Methodology for the Effects of Controllable Demand-Side Management in Demand and Energy Forecasts.**

2. **Number:** MOD-021-0

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual Demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management (DSM) programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Transmission Planner

   4.3. Resource Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Load-Serving Entity Transmission Planner and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.

R2. The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R1.

R3. The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).

C. Measures

M1. The Load-Serving Entity, Transmission Planner and Resource Planner forecasts clearly document how the demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible demands, and Direct Control Load Management) are addressed.

M2. The Load-Serving Entity, Transmission Planner and Resource Planner information detailing how Demand-Side Management measures are addressed in the forecasts of Peak Demand and annual Net Energy for Load are included in the data reporting procedures of Reliability Standard MOD-016-0_R1.

M3. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide evidence to its Compliance Monitor that it provided documentation on the treatment of DSM programs to NERC as requested (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation on the treatment of DSM programs in the demand and energy forecasts was provided, but was incomplete.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Documentation on the treatment of DSM programs in the demand and energy forecasts was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Verification of Generator Gross and Net Real Power Capability**
2. **Number:** MOD-024-1
3. **Purpose:** To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.
4. **Applicability**
   - **4.1.** Regional Reliability Organization.
   - **4.2.** Generation Owner.
5. **Effective Dates:**

   Requirement 1 and Requirement 2 **—** April 1, 2006.

   Requirement 3 — January 1, 2007.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:

- **R1.1.** Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.
- **R1.2.** Criteria for reporting generating unit auxiliary loads.
- **R1.3.** Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.
- **R1.4.** Periodicity and schedule of model and data verification and reporting.
- **R1.5.** Information to be verified and reported:
  - **R1.5.1.** Seasonal gross and net Real Power generating capabilities.
  - **R1.5.2.** Real power requirements of auxiliary loads.
  - **R1.5.3.** Method of verification, including date and conditions.

R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its gross and net Real Power generating capability per R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Real Power capability in accordance with R1.

M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to those procedures, for verification and reporting of generator gross and net Real Power capability were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Real Power capability, consistent with that Regional Reliability Organization's procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC

For Generator Owner: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain both the current and previous versions of the procedures.

The Generator Owner shall retain information from the most current and prior verification.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Regional Reliability Organization:

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 Procedures did not meet one of the following requirements: R1.1, R1.2, R1.4

2.1.2 No evidence that procedures were distributed as required in R2.

2.2. Level 2: There shall be a level two non-compliance if **both** of the following conditions are present:

2.2.1 Procedures did not meet two of the following requirements: R1.1, R1.2, R1.4

2.2.2 No evidence that procedures were distributed as required in R2.

2.3. Level 3: Procedures did not meet R1.3.

2.4. Level 4: Procedures did not meet either R1.5.1, R1.5.2 or R1.5.3

3. Levels of Non-Compliance for Generator Owner:

3.1. Level 1: Complete, verified generator data were provided for 98% or more but less than 100% of a generator owner's units as required by the regional procedures.

3.2. Level 2: Complete, verified generator data were provided for than 96% or more, but less than 98% of a generator owner’s units as required by the regional procedures.

3.3. Level 3: Complete, verified generator data were provided for 94% or more, but less than 96% of a generator owner’s units as required by the regional procedures.

3.4. Level 4: Complete, verified generator data were provided for less than 94% of a generator owner’s units as required by the regional procedures.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	12/01/05	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3. 8. Removed the word “less” after 94% in section 3.4. Level 4.	01/20/06

A. Introduction

1. **Title:** **Verification of Generator Gross and Net Reactive Power Capability**

2. **Number:** MOD-025-1

3. **Purpose:** To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Effective Dates:**

   Requirement 1 and Requirement 2 — January 1, 2007

   Requirement 3:

   January 1, 2008 — 1st 20% compliant

   January 1, 2009 — 2nd 20% compliant

   January 1, 2010 — 3rd 20% compliant

   January 1, 2011 — 4th 20% compliant

   January 1, 2012 — 5th 20% compliant

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:

R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

R1.2. Criteria for reporting generating unit auxiliary loads.

R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of commissioning data, performance tracking, engineering analysis, testing, etc.

R1.4. Periodicity and schedule of model and data verification and reporting.

R1.5. Information to be reported:

R1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1.

R1.5.2. Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc.

R1.5.3. Verified Reactive Power of auxiliary loads.

R1.5.4. Method of verification, including date and conditions.

R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the

Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its gross and net Reactive Power generating capability per R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Reactive Power capability in accordance with R1.

M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to these procedures, for verification and reporting of generator gross and net Reactive Power capability were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Reactive Power capability, consistent with that Regional Reliability Organization's procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC.

For Generator Owner: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain both the current and previous version of the procedures.

The Generator Owner shall retain information from the most current and prior verification.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Regional Reliability Organization:

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 Procedures did not meet one of the following requirements: R1.1, R1.2 or R1.4.

2.1.2 No evidence that procedures were distributed as required in R2.

2.2. Level 2: Procedures did not meet two or three of the following requirements: R1.1, R1.2 or R1.4.

2.3. Level 3: Procedures did not meet R1.3.

2.4. Level 4: Procedures did not meet R1.5.1, R1.5.2, R1.5.3, or R1.5.4.

3. Levels of Non-Compliance for Generator Owner:

3.1. Level 1: Complete, verified generator data were provided for 98% or more but less than 100% of a Generator Owner's units as required by the regional procedures.

3.2. Level 2: Complete, verified generator data were provided for than 96% or more, but less than 98% of a Generator Owner's units as required by the regional procedures.

3.3. Level 3: Complete, verified generator data were provided for 94% or more, but less than 96% of a Generator Owner's units as required by the regional procedures.

3.4. Level 4: Complete, verified generator data were provided for less than 94% less of a Generator Owner's units as required by the regional procedures.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	12/01/05	1. Changed tabs in footer. 2. Removed comma after 2004 in "Development Steps Completed," #1. 3. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 4. Added "periods" to items where appropriate. 5. Changed apostrophes to "smart" symbols. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all instances of "regional" in section D.3.	01/20/06

A. Introduction

1. **Title:** **Operating Personnel Responsibility and Authority**

2. **Number:** PER-001-0

3. **Purpose:** Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

C. Measures

M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:

M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The position description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.

M1.2 The current job description is readily accessible in the control room environment to all operating personnel.

M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.

M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. **Compliance Monitoring Process**

   Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Operating Personnel Training**
2. **Number:** PER-002-0
3. **Purpose:** Each Transmission Operator and Balancing Authority must provide their personnel with a coordinated training program that will ensure reliable system operation.
4. **Applicability**
   - **4.1.** Balancing Authority.
   - **4.2.** Transmission Operator.
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.

R2. Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:

R2.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.

R2.2. Positions directly responsible for complying with NERC standards.

R3. For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:

R3.1. A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.

R3.2. The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.

R3.3. The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.

R3.4. Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.

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.

C. Measures

M1. The Transmission Operator and Balancing Authority operating personnel training program shall be reviewed to ensure that it is designed to promote reliable system operations.

D. Compliance

1. Compliance Monitoring Process

Periodic Review: The Regional Reliability Organization will conduct an on-site review of the Transmission Operator and Balancing Authority operating personnel training program every three years. The operating personnel training records will be reviewed and assessed compared to the program curriculum.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority will annually provide a self-certification based on Requirements R1 through R4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Three years.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: The Transmission Operator or Balancing Authority operating personnel training program does not address all elements of Requirement R3.

2.3. Level 3: The Transmission Operator or Balancing Authority operating personnel training program does not address Requirement R4.

2.4. Level 4: A Transmission Operator or Balancing Authority has not provided a training program for its operating personnel.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Proposed Effective Date	Errata

A. Introduction

1. **Title:** **Operating Personnel Credentials**

2. **Number:** PER-003-0

3. **Purpose:** Certification of operating personnel is necessary to ensure minimum competencies for operating a reliable Bulk Electric System.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with personnel that are NERC-certified for the applicable functions:

R1.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.

R1.2. Positions directly responsible for complying with NERC standards.

C. Measures

M1. Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall have NERC-certified operating personnel on shift in required positions at all times with the following exceptions:

M1.1 While in training, an individual without the proper NERC certification credential may not independently fill a required operating position. Trainees may perform critical tasks only under the direct, continuous supervision and observation of the NERC-certified individual filling the required position.

M1.2 During a real-time operating emergency, the time when control is transferred from a primary control center to a backup control center shall not be included in the calculation of non-compliance. This time shall be limited to no more than four hours.

D. Compliance

1. **Compliance Monitoring Process**

Periodic Review: An on-site review will be conducted every three years. Staffing schedules and certification numbers will be compared to ensure that positions that require NERC-certified operating personnel were covered as required. Certification numbers from the Transmission Operator, Balancing Authority, and Reliability Coordinator will be compared with NERC records.
Exception Reporting: Any violation of the standard must be reported to the Regional Reliability Organization, who will inform the NERC Vice President-Compliance, indicating the reason for the non-compliance and the mitigation plans taken.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month without a violation.

1.3. Data Retention

Present calendar year plus previous calendar year staffing plan.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 0 hours and up to 12 hours during a one calendar month period for each required position in the staffing plan.

2.2. Level 2: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 12 hours and up to 36 hours during a one calendar month period for each required position in the staffing plan.

2.3. Level 3: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 36 hours and up to 72 hours during a one-month calendar period for each required position in the staffing plan.

2.4. Level 4: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 72 hours during a one calendar month period for each required position in the staffing plan.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Reliability Coordination — Staffing**

2. **Number:** PER-004-0

3. **Purpose:**

   Reliability Coordinators must have sufficient, competent staff to perform the Reliability Coordinator functions.

4. **Applicability**

   4.1. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.

R2. All Reliability Coordinator operating personnel shall each complete a minimum of 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.

R3. Reliability Coordinator operating personnel shall have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas.

R4. Reliability Coordinator operating personnel shall have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.

R5. Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. Title: **System Protection Coordination**

2. Number: PRC-001-0

3. Purpose:

To ensure system protection is coordinated among operating entities.

4. Applicability

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

5. Effective Date: April 1, 2005

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

Not specified

D. Compliance

Not specified

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata

A. Introduction

1. **Title:** **Define and Document Disturbance Monitoring Equipment Requirements.**

2. **Number:** PRC-002-0

3. **Purpose:** To ensure that Disturbance monitoring equipment is installed in a uniform manner to facilitate development of models and analyses of events.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Regional Reliability Organization shall develop comprehensive requirements for the installation of Disturbance monitoring equipment to ensure data is available to determine system performance and the causes of System Disturbances. The comprehensive requirements shall include all of the following:

R1.1. Type of data recording capability (e.g., sequence-of-event, Fault recording, dynamic Disturbance recording).

R1.2. Equipment characteristics including but not limited to:

R1.2.1. Recording duration requirements.

R1.2.2. Time synchronization requirements.

R1.2.3. Data format requirements.

R1.2.4. Event triggering requirements

R1.3. Monitoring, recording, and reporting capabilities of the equipment.

R1.3.1. Voltage.

R1.3.2. Current.

R1.3.3. Frequency.

R1.3.4. MW and/or MVAR, as appropriate.

R1.4. Data retention capabilities (e.g., length of time data is to be available for retrieval).

R1.5. Regional coverage requirements (e.g., by voltage, geographic area, electric area or subarea).

R1.6. Installation requirements:

R1.6.1. Substations.

R1.6.2. Transmission lines.

R1.6.3. Generators.

R1.7. Responsibility for maintenance and testing.

R1.8. Requirements for periodic (at least every five years) updating, review, and approval of the Regional requirements.

R2. The Regional Reliability Organization shall provide its requirements for the installation of Disturbance monitoring equipment to other Regional Reliability Organizations and NERC on request (30 calendar days).

C. Measures

M1. The Regional Reliability Organization's requirements for the installation of Disturbance monitoring equipment shall address all elements listed in Reliability Standard PRC-002-0_R1.

M2. The Regional Reliability Organization shall have evidence it provided its requirements for the installation of Disturbance monitoring equipment to other Regional Reliability Organizations and NERC on request (30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request by NERC (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's Disturbance monitoring requirements do not address one of the eight requirements contained in Reliability Standard PRC-002-0_R1.

2.2. Level 2: The Regional Reliability Organization's Disturbance monitoring requirements do not address two of the eight requirements contained in Reliability Standard PRC-002-0_R1.

2.3. Level 3: The Regional Reliability Organization's Disturbance monitoring requirements do not address three of the eight requirements contained in Reliability Standard PRC-002-0_R1.

2.4. Level 4: The Regional Reliability Organization's Disturbance monitoring requirements were not provided or do not address four or more of the eight requirements contained in Reliability Standard PRC-002-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems**
2. **Number:** PRC-003-1
3. **Purpose:** To ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
   4.1. Regional Reliability Organization
5. **Effective Date:** May 1, 2006.

B. Requirements

R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:

R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).

R1.2. Data reporting requirements (periodicity and format) for Misoperations.

R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.

R1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.

R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.

R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.

C. Measures

M1. The Regional Reliability Organization shall have procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in R1.

M2. The Regional Reliability Organization shall have evidence it maintained and periodically updated its procedures for review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in Requirement 2.

M3. The Regional Reliability Organization shall have evidence it provided its procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in Requirement 3.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain documentation of its procedures for analysis of transmission and generation Protection System Misoperations and any changes to those procedures for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Procedures were not reviewed and updated within the review cycle period as required in R2.

2.2. Level 2: Procedures did not include one of the elements defined in R1.1 through R1.4.

2.3. Level 3: Procedures did not include two or more of the elements defined in R1.1 through R1.4.

2.4. Level 4: There shall be a level four non-compliance if either of the following conditions exist:

2.4.1 No evidence of Procedures.

2.4.2 Procedures were not provided to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in R3.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06

A. Introduction

1. **Title:** **Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

2. **Number:** PRC-004-1

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. **Effective Date:** August 1, 2006

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization procedures developed for PRC-003 R1.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Reliability Organization procedures developed for PRC-003 R1.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Transmission Owners and Distribution Providers that own a Transmission Protection System:

2.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R1, but documentation of Corrective Action Plans is incomplete.

2.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R1 and documentation of Corrective Action Plans is incomplete.

2.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R1 and there are no associated Corrective Action Plans.

2.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to Requirement 3.

3. Levels of Non-Compliance for Generator Owners

3.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R2, but documentation of Corrective Action Plans is incomplete.

3.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R2 and documentation of Corrective Action Plans is incomplete.

3.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R2 and there are no associated Corrective Action Plans.

3.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to R3.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06

A. Introduction

1. **Title:** **Transmission and Generation Protection System Maintenance and Testing**

2. **Number:** PRC-005-1

3. **Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Generator Owner.

   4.3. Distribution Provider that owns a transmission Protection System.

5. **Effective Date:** May 1, 2006

B. Requirements

R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:

R1.1. Maintenance and testing intervals and their basis.

R1.2. Summary of maintenance and testing procedures.

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.

C. Measures

M1. 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 an associated Protection System maintenance and testing program as defined in Requirement 1.

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.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program provided was incomplete as required in R1, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. Level 2: Documentation of the maintenance and testing program provided was complete as required in R1, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. Level 3: Documentation of the maintenance and testing program provided was incomplete, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/05

A. Introduction

1. **Title:** **Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs**

2. **Number:** PRC-006-0

3. **Purpose:** Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall develop, coordinate, and document an UFLS program, which shall include the following:

R1.1. Requirements for coordination of UFLS programs within the subregions, Regional Reliability Organization and, where appropriate, among Regional Reliability Organizations.

R1.2. Design details shall include, but are not limited to:

R1.2.1. Frequency set points.

R1.2.2. Size of corresponding load shedding blocks (% of connected loads.)

R1.2.3. Intentional and total tripping time delays.

R1.2.4. Generation protection.

R1.2.5. Tie tripping schemes.

R1.2.6. Islanding schemes.

R1.2.7. Automatic load restoration schemes.

R1.2.8. Any other schemes that are part of or impact the UFLS programs.

R1.3. A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.

R1.4. Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to:

R1.4.1. A review of the frequency set points and timing, and

R1.4.2. Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between Demand (Load) and generation.

R2. The Regional Reliability Organization shall provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days).

R3. The Regional Reliability Organization shall provide documentation of the assessment of its UFLS program to NERC on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization shall have documentation of the UFLS program and current UFLS database.

M2. The Regional Reliability Organization shall have evidence it provided documentation of its UFLS program and its database information to NERC as specified in Reliability Standard PRC-006-0_R2.

M3. The Regional Reliability Organization shall have evidence it provided documentation of its assessment of its UFLS program to NERC as specified in Reliability Standard PRC-006-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days) for the program, database, and results of assessments.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation demonstrating the coordination of the Regional Reliability Organization's UFLS program was incomplete in one of the elements in Reliability Standard PRC-006-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Documentation demonstrating the coordination of the Regional Reliability Organization's UFLS program was incomplete in two or more requirements or documentation demonstrating the coordination of the Regional Reliability Organization's UFLS program was not provided, or an assessment was not completed in the last five years.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organization's Underfrequency Load Shedding Program Requirements**

2. **Number:** PRC-007-0

3. **Purpose:** Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. **Applicability:**

   4.1. Transmission Owner required by its Regional Reliability Organization to own a UFLS program

   4.2. Transmission Operator required by its Regional Reliability Organization to operate a UFLS program

   4.3. Distribution Provider required by its Regional Reliability Organization to own or operate a UFLS program

   4.4. Load-Serving Entity required by its Regional Reliability Organization to operate a UFLS program

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.

R2. The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database.

R3. The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).

C. Measures

M1. Each Transmission Owner's and Distribution Provider's UFLS program shall be consistent with its associated Regional Reliability Organization's UFLS program requirements.

M2. Each Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program shall have evidence that it provided its associated Regional Reliability Organization and NERC with documentation of the UFLS program on request (30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The evaluation of the entity's UFLS program for consistency with its Regional Reliability Organization's UFLS program is incomplete or inconsistent in one or more requirements of Reliability Standard PRC-006-0_R1, but is consistent with the required amount of Load shedding.

2.2. Level 2: The amount of Load shedding is less than 95percent of the Regional requirement in any of the Load steps.

2.3. Level 3: The amount of Load shedding is less than 90percent of the Regional requirement in any of the Load steps.

2.4. Level 4: The evaluation of the entity's UFLS program for consistency with its Regional Reliability Organization's UFLS program was not provided or the amount of Load shedding is less than 85 percent of the Regional requirement on any of the Load steps.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program**

2. **Number:** PRC-008-0

3. **Purpose:** Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. **Applicability:**

   4.1. Transmission Owner required by its Regional Reliability Organization to have a UFLS program

   4.2. Distribution Provider required by its Regional Reliability Organization to have a UFLS program

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

R2. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).

C. Measures

M1. Each Transmission Owner's and Distribution Provider's UFLS equipment maintenance and testing program contains the elements specified in Reliability Standard PRC-008-0_R1.

M2. Each Transmission Owner and Distribution Provider shall have evidence that it provided the results of its UFLS equipment maintenance and testing program's implementation to its Regional Reliability Organization and NERC on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (within 30 calendar days).

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.2. Level 2: Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

2.3. Level 3: Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	September 26, 2005	Fixed reference in M1 from PRC-007-0_R1 to PRC-008-0_R1.	Errata

A. Introduction

1. **Title:** **Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event**
2. **Number:** PRC-009-0
3. **Purpose:** Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.
4. **Applicability:**
   - **4.1.** Transmission Owner required by its Regional Reliability Organization to own a UFLS program
   - **4.2.** Transmission Operator required by its Regional Reliability Organization to operate a UFLS program
   - **4.3.** Load-Serving Entity required by the Regional Reliability Organization to operate a UFLS program
   - **4.4.** Distribution Provider required by the Regional Reliability Organization to own or operate a UFLS program
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:

- **R1.1.** A description of the event including initiating conditions.
- **R1.2.** A review of the UFLS set points and tripping times.
- **R1.3.** A simulation of the event.
- **R1.4.** A summary of the findings.

R2. The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.

C. Measures

M1. Each Transmission Owner's, Transmission Operator's, Load-Serving Entity's and Distribution Provider's documentation of the UFLS program performance following an underfrequency event includes all elements identified in Reliability Standard PRC-009-0_R1.

M2. Each Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operate a UFLS program, shall have evidence it provided documentation of the analysis of the UFLS program performance following an underfrequency event as specified in Reliability Standard PRC-009-0_R1.

D. Compliance

1. **Compliance Monitoring Process**

    1.1. **Compliance Monitoring Responsibility**

    Compliance Monitor: Regional Reliability Organization.

    1.2. **Compliance Monitoring Period and Reset Timeframe**

    On request 90 calendar days after the system event.

    1.3. **Data Retention**

    None specified.

    1.4. **Additional Compliance Information**

    None.

2. **Levels of Non-Compliance**

    2.1. **Level 1:** Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was incomplete in one or more elements in Reliability Standard PRC-009-0_R1.

    2.2. **Level 2:** Not applicable.

    2.3. **Level 3:** Not applicable.

    2.4. **Level 4:** Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program.**

2. **Number:** PRC-010-0

3. **Purpose:** Provide System preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program.

4. **Applicability:**

 4.1. Load-Serving Entity that operates a UVLS program

 4.2. Transmission Owner that owns a UVLS program

 4.3. Transmission Operator that operates a UVLS program

 4.4. Distribution Provider that owns or operates a UVLS program

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program. This assessment shall be conducted with the associated Transmission Planner(s) and Planning Authority(ies).

R1.1. This assessment shall include, but is not limited to:

R1.1.1. Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.

R1.1.2. Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.

R1.1.3. A review of the voltage set points and timing.

R2. The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days).

C. Measures

M1. Each Transmission Owner's and Distribution Provider's UVLS program shall include the elements identified in Reliability Standard PRC-010-0_R1.

M2. Each Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall have evidence it provided documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC as specified in Reliability Standard PRC-010-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

Assessments every five years or as required by System changes.

Current assessment on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: An assessment of the UVLS program did not address one of the three requirements listed in Reliability Standard PRC-010-0_R1.1 or an assessment of the UVLS program was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Undervoltage Load Shedding System Maintenance and Testing**

2. **Number:** PRC-011-0

3. **Purpose:** Provide system preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program.

4. **Applicability:**

   4.1. Transmission Owner that owns a UVLS system

   4.2. Distribution Provider that owns a UVLS system

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program shall include:

R1.1. The UVLS system identification which shall include but is not limited to:

R1.1.1. Relays.

R1.1.2. Instrument transformers.

R1.1.3. Communications systems, where appropriate.

R1.1.4. Batteries.

R1.2. Documentation of maintenance and testing intervals and their basis.

R1.3. Summary of testing procedure.

R1.4. Schedule for system testing.

R1.5. Schedule for system maintenance.

R1.6. Date last tested/maintained.

R2. The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).

C. Measures

M1. Each Transmission Owner and Distribution Provider that owns a UVLS system shall have documentation that its UVLS equipment maintenance and testing program conforms with Reliability Standard PRC-011-0_R1.

M2. Each Transmission Owner and Distribution Provider that owns a UVLS system shall have evidence it provided documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program as specified in Reliability Standard PRC-011-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program was complete, but records indicate implementation was not on schedule.

2.2. Level 2: Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.3. Level 3: Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	October 12, 2005	Level 2 Non-Compliance: Changed “incomplete” to “complete” and inserted “not” between “was” and “on.”	Errata

A. Introduction

1. **Title:** **Special Protection System Review Procedure**
2. **Number:** PRC-012-0
3. **Purpose:** To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**

   4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:

R1.1. Description of the process for submitting a proposed SPS for Regional Reliability Organization review.

R1.2. Requirements to provide data that describes design, operation, and modeling of an SPS.

R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.

R1.4. Requirements to demonstrate that the inadvertent operation of an SPS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.

R1.5. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.

R1.6. Regional Reliability Organization definition of misoperation.

R1.7. Requirements for analysis and documentation of corrective action plans for all SPS misoperations.

R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.

R1.9. Determination, as appropriate, of maintenance and testing requirements.

R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its SPS review procedure on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use an SPS shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-0_R1.

M2. The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its SPS review procedure on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the Regional Reliability Organization's procedure is missing one of the items listed in Reliability Standard PRC-012-0_R1.

2.2. Level 2: Documentation of the Regional Reliability Organization's procedure is missing two of the items listed in Reliability Standard PRC-012-0_R1.

2.3. Level 3: Documentation of the Regional Reliability Organization's procedure is missing three of the items listed in Reliability Standard PRC-012-0_R1.

2.4. Level 4: Documentation of the Regional Reliability Organization's procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Special Protection System Database.**

2. **Number:** PRC-013-0

3. **Purpose:** To ensure that all Special Protection Systems (SPSs) are properly designed, meet performance requirements, and are coordinated with other protection systems.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information:

R1.1. Design Objectives — Contingencies and system conditions for which the SPS was designed,

R1.2. Operation — The actions taken by the SPS in response to Disturbance conditions, and

R1.3. Modeling — Information on detection logic or relay settings that control operation of the SPS.

R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with an SPS installed, shall have an SPS database as defined in PRC-013-0_R1 of this Reliability Standard.

M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (within 30 calendar days.)

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

2.1. Level 1: The Regional Reliability Organization's database is missing one of the items listed in Reliability Standard PRC-013-0_R1.

2.2. Level 2: The Regional Reliability Organization's database is missing two of the items listed in Reliability Standard PRC-013-9_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Dave	New

A. Introduction

1. **Title:** **Special Protection System Assessment**
2. **Number:** PRC-014-0
3. **Purpose:** To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
   4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.

R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all SPSs installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).

R3. The documentation of the Regional Reliability Organization's SPS assessment shall include the following elements:

R3.1. Identification of group conducting the assessment and the date the assessment was performed.

R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.

R3.3. Identification of SPSs that were found not to comply with NERC standards and Regional Reliability Organization criteria.

R3.4. Discussion of any coordination problems found between a SPS and other protection and control systems.

R3.5. Provide corrective action plans for non-compliant SPSs.

C. Measures

M1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.

M2. The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).

M3. The Regional Reliability Organization's documentation of the SPS assessment shall include all elements as defined in Reliability Standard PRC-014-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The summary (or detailed) Regional SPS assessment is missing one of the items listed in Reliability Standard PRC-014-0_R3.

2.2. Level 2: The summary (or detailed) Regional SPS assessment is missing two of the items listed in Reliability Standard PRC-014-0_3.

2.3. Level 3: The summary (or detailed) Regional SPS assessment is missing three of the items listed in Reliability Standard PRC-014-0_R3.

2.4. Level 4: The summary (or detailed) Regional SPS assessment is missing more than three of the items listed in Reliability Standard PRC-014-0_R3 or was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Special Protection System Data and Documentation**

2. **Number:** PRC-015-0

3. **Purpose:** To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

4. **Applicability:**

   4.1. Transmission Owner that owns an SPS

   4.2. Generator Owner that owns an SPS

   4.3. Distribution Provider that owns an SPS

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R1.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.

R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it maintains a list of and provides data for existing and proposed SPSs as defined in Reliability Standard PRC-013-0_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.

M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: SPS owners provided SPS data, but was incomplete according to the Regional Reliability Organization SPS database requirements.

2.2. Level 2: SPS owners provided results of studies that show compliance of new or functionally modified SPSs with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-0_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: No SPS data was provided in accordance with Regional Reliability Organization SPS database requirements for Standard PRC-012-0_R1, or the results of studies that show compliance of new or functionally modified SPSs with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-0_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Special Protection System Misoperations**

2. **Number:** PRC-016-0

3. **Purpose:** To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

4. **Applicability:**

   4.1. Transmission Owner that owns an SPS

   4.2. Generator Owner that owns an SPS

   4.3. Distribution Provider that owns an SPS

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.

R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it analyzed SPS operations and maintained a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-016-0_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it took corrective actions to avoid future misoperations.

M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of SPS misoperations is complete but documentation of corrective actions taken for all identified SPS misoperations is incomplete.

2.2. Level 2: Documentation of corrective actions taken for SPS misoperations is complete but documentation of SPS misoperations is incomplete.

2.3. Level 3: Documentation of SPS misoperations and corrective actions is incomplete.

2.4. Level 4: No documentation of SPS misoperations or corrective actions.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Special Protection System Maintenance and Testing**

2. **Number:** PRC-017-0

3. **Purpose:** To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

4. **Applicability:**

   4.1. Transmission Owner that owns an SPS

   4.2. Generator Owner that owns an SPS

   4.3. Distribution Provider that owns an SPS

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:

R1.1. SPS identification shall include but is not limited to:

R1.1.1. Relays.

R1.1.2. Instrument transformers.

R1.1.3. Communications systems, where appropriate.

R1.1.4. Batteries.

R1.2. Documentation of maintenance and testing intervals and their basis.

R1.3. Summary of testing procedure.

R1.4. Schedule for system testing.

R1.5. Schedule for system maintenance.

R1.6. Date last tested/maintained.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-0_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Timeframe:
On request (30 calendar days.)

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance Monitor: Regional Reliability Organization.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.2. Level 2: Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

2.3. Level 3: Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Under-Voltage Load Shedding Program Database**

2. **Number:** PRC-020-1

3. **Purpose:** Ensure that a regional database is maintained for Under-Voltage Load Shedding (UVLS) programs implemented by entities within the Region to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES). Ensure the UVLS database is available for Regional studies and for dynamic studies and simulations of the BES.

4. **Applicability**

   4.1. Regional Reliability Organization with entities that own or operate a UVLS program.

5. **Effective Date:** May 1, 2006

B. Requirements

R1. The Regional Reliability Organization shall establish, maintain and annually update a database for UVLS programs implemented by entities within the region to mitigate the risk of voltage collapse or voltage instability in the BES. This database shall include the following items:

R1.1. Owner and operator of the UVLS program.

R1.2. Size and location of customer load, or percent of connected load, to be interrupted.

R1.3. Corresponding voltage set points and overall scheme clearing times.

R1.4. Time delay from initiation to trip signal.

R1.5. Breaker operating times.

R1.6. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.

R2. The Regional Reliability Organization shall provide the information in its UVLS database to the Planning Authority, the Transmission Planner, or other Regional Reliability Organizations and to NERC within 30 calendar days of a request.

C. Measures

M1. The Regional Reliability Organization shall have evidence that it established and annually updated its UVLS database to include all elements in Requirement 1.1 through 1.6.

M2. The Regional Reliability Organization shall have evidence that it provided the information in its UVLS database to the requesting entities and to NERC in accordance with Requirement 2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   NERC

   1.2. Compliance Monitoring Period and Reset Time Frame

   One calendar year.

   1.3. Data Retention

The Regional Reliability Organization shall retain the current and prior annual updated database. The Compliance Monitor shall retain all audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Did not update its UVLS database annually.

2.2. Level 2: UVLS program database information provided, but did not include all of the items identified in R1.1 through R1.6.

2.3. Level 3: Not applicable.

2.4. Level 4: Did not provide information from its UVLS program database.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	12/01/05	1. Removed comma after 2004 in “Development Steps Completed,” #1. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate. 4. Added or removed “periods” where appropriate. 5. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06

A. Introduction

1. **Title:** **Under-Voltage Load Shedding Program Data**

2. **Number:** PRC-021-1

3. **Purpose:** Ensure data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).

4. **Applicability**

   4.1. Transmission Owner that owns a UVLS program.

   4.2. Distribution Provider that owns a UVLS program.

5. **Effective Date:** August 1, 2006

B. Requirements

R1. Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:

R1.1. Size and location of customer load, or percent of connected load, to be interrupted.

R1.2. Corresponding voltage set points and overall scheme clearing times.

R1.3. Time delay from initiation to trip signal.

R1.4. Breaker operating times.

R1.5. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems. .

R2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.

C. Measures

M1. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have documentation that its UVLS data was updated annually and includes all items specified in Requirement 1.1 through 1.5.

M2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have evidence it provided the Regional Reliability Organization with its UVLS program data within 30 calendar days of a request.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   One calendar year.

   1.3. Data Retention

Each Transmission Owner and Distribution Provider that owns a UVLS program shall retain a copy of the data submitted over the past two years.

The Compliance Monitor shall retain all audit data for three years.

1.4. Additional Compliance Information

Transmission Owner and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Did not update its UVLS data annually.

2.2. Level 2: UVLS data was provided, but did not address one of the items identified in R1.1 through R1.5.

2.3. Level 3: UVLS data was provided, but did not address two or more of the items identified in R1.1 through R1.5.

2.4. Level 4: Did not provide any UVLS data.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	12/01/05	1. Removed comma after 2004 in “Development Steps Completed,” #1. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Added heading above table “Future Development Plan.” 4. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate. 5. Added or removed “periods” where appropriate. **6.** Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/05

A. Introduction

1. **Title:** **Under-Voltage Load Shedding Program Performance**

2. **Number:** **PRC-022-1**

3. **Purpose:** Ensure that Under Voltage Load Shedding (UVLS) programs perform as intended to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).

4. **Applicability**

   4.1. Transmission Operator that operates a UVLS program.

   4.2. Distribution Provider that operates a UVLS program.

   4.3. Load-Serving Entity that operates a UVLS program.

5. **Effective Date:** May 1, 2006

B. Requirements

R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include:

R1.1. A description of the event including initiating conditions.

R1.2. A review of the UVLS set points and tripping times.

R1.3. A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient and dynamic simulations may not be needed.

R1.4. A summary of the findings.

R1.5. For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.

R2. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request.

C. Measures

M1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall have documentation of its analysis of UVLS operations and Misoperations in accordance with Requirement 1.1 through 1.5.

M2. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall have evidence that it provided documentation of its analysis of UVLS program performance within 90 calendar days of a request by the Regional Reliability Organization.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall retain documentation of its analyses of UVLS operations and Misoperations for two years. The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

Transmission Operator, Load-Serving Entity, and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Documentation of the analysis of UVLS performance was provided but did not include one of the five requirements in R1.

2.3. Level 3: Documentation of the analysis of UVLS performance was provided but did not include two or more of the five requirements in R1.

2.4. Level 4: Documentation of the analysis of UVLS performance was not provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	12/01/05	1. Removed comma after 2004 in “Development Steps Completed,” #1. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate. 4. Added or removed “periods” where appropriate. 5. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06

A. Introduction

1. **Title:** **Reliability Responsibilities and Authorities**

2. **Number:** TOP-001-0

3. **Purpose:**

   To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

   4.4. Distribution Providers

   4.5. Load Serving Entities

5. **Effective Date:** April 1, 2005

B. Requirements

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.

R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.

R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:

R7.1. For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.2. For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.3. When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.

R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Normal Operations Planning**

2. **Number:** TOP-002-0

3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Transmission Operator.

   4.3. Generation Operator.

   4.4. Load Serving Entity.

   4.5. Transmission Service Provider.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

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:

R14.1. Changes in real and reactive output capabilities.

R14.2. Automatic Voltage Regulator status and mode setting.

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Planned Outage Coordination**

2. **Number:** TOP-003-0

3. **Purpose:** Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.

4. **Applicability**

   4.1. Generator Operators.

   4.2. Transmission Operators.

   4.3. Balancing Authorities.

   4.4. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Generator Operators and Transmission Operators shall provide planned outage information.

R1.1. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.

R1.2. Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.

R1.3. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.

R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

M1. Evidence that the Generator Operator, Transmission Operator, Balancing Authority, and Reliability Coordinator reported and coordinated scheduled outage information as indicated in the requirements above.

D. Compliance

1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to “not be taken” because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Each entity responsible for reporting information under Requirements R1 and R3 has a process in place to provide information to their Reliability Coordinator but does not have a process in place (where permitted by legal agreements) to provide this information to the neighboring Balancing Authority or Transmission Operator.

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: There is no process in place to exchange outage information, or the entity responsible for reporting information under Requirements R1 to R3 does not follow the directives of the Reliability Coordinator to cancel or reschedule an outage.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Transmission Operations**
2. **Number:** TOP-004-0
3. **Purpose:** To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.
4. **Applicability:**
   4.1. Transmission Operators
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.

R3. Each Transmission Operator shall, when practical, operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by Regional Reliability Organization policy.

R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.

R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.

R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:

R6.1. Equipment ratings.

R6.2. Monitoring and controlling voltage levels and real and reactive power flows.

R6.3. Switching transmission elements.

R6.4. Planned outages of transmission elements.

R6.5. Development of IROLs and SOLs.

R6.6. Responding to IROL and SOL violations.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Operational Reliability Information**
2. **Number:** TOP-005-1
3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
4. **Applicability**
   - **4.1.** Transmission Operators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Reliability Coordinators.
   - **4.4.** Purchasing Selling Entities.
5. **Effective Date:** November 1, 2006

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.

R1.1. Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.

R2. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."

R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

R4. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

M1. Evidence that the Reliability Coordinator, Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance Monitoring Responsibility**

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Each entity responsible for reporting information under Requirements R1 to R5 is providing the requesting entities with the data required, in specified time intervals and format, but there are problems with consistency of delivery identified in the measuring process that need remedy (e.g., the data is not supplied consistently due to equipment malfunctions, or scaling is incorrect).

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: Each entity responsible for reporting information under Requirements R1 to R5 is not providing the requesting entities with data with the specified content, timeliness, or format. The information missing is included in the requesting entity's list of data.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

Attachment 1-TOP-005-0

Electric System Reliability Data

This Attachment lists the types of data that Reliability Coordinators, Balancing Authorities, and Transmission Operators are expected to provide, and are expected to share with each other.

1. The following information shall be updated at least every ten minutes:

1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:

1.1.1 Status.

1.1.2 MW or ampere loadings.

1.1.3 MVA capability.

1.1.4 Transformer tap and phase angle settings.

1.1.5 Key voltages.

1.2. Generator data.

1.2.1 Status.

1.2.2 MW and MVAR capability.

1.2.3 MW and MVAR net output.

1.2.4 Status of automatic voltage control facilities.

1.3. Operating reserve.

1.3.1 MW reserve available within ten minutes.

1.4. Balancing Authority demand.

1.4.1 Instantaneous.

1.5. Interchange.

1.5.1 Instantaneous actual interchange with each Balancing Authority.

1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.

1.5.3 Interchange Schedules for the next 24 hours.

1.6. Area Control Error and frequency.

1.6.1 Instantaneous area control error.

1.6.2 Clock hour area control error.

1.6.3 System frequency at one or more locations in the Balancing Authority.

2. Other operating information updated as soon as available.

2.1. Interconnection Reliability Operating Limits and System Operating Limits in effect.

2.2. Forecast of operating reserve at peak, and time of peak for current day and next day.

2.3. Forecast peak demand for current day and next day.

2.4. Forecast changes in equipment status.

2.5. New facilities in place.

2.6. New or degraded special protection systems.

2.7. Emergency operating procedures in effect.

2.8. Severe weather, fire, or earthquake.

2.9. Multi-site sabotage.

A. Introduction

1. **Title:** **Monitoring System Conditions**

2. **Number:** TOP-006-0

3. **Purpose:**

   To ensure critical reliability parameters are monitored in real-time.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Generator Operators.

   4.4. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.

R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.

R4. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system’s near-term load pattern.

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations

2. **Number:** TOP-007-0

3. **Purpose:**

   This standard ensures SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.

R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.

R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.

R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.

C. Measures

M1. Evidence that the Transmission Operator informed the Reliability Coordinator when an IROL or SOL was exceeded and the actions taken to return the system to within limits.

M2. Evidence that the Transmission Operator returned the system to within IROL within 30 minutes for each incident that an IROL, or SOL that became an IROL due to changed system conditions, was exceeded.

M3. Evidence that the Reliability Coordinator evaluated actions and provided direction required to return the system to within limits.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   The Reliability Coordinator shall report any IROL violation exceeding 30 minutes to the Regional Reliability Organization and NERC within 72 hours. Each Regional Reliability Organization shall report any such violations to NERC via the NERC compliance reporting process. The Reliability Coordinator shall report any SOL violation that has become an IROL violation because of changed system conditions; i.e. exceeding the limit will require action to prevent:

1.1.1. System instability.

1.1.2. Unacceptable system dynamic response or equipment tripping.

1.1.3. Voltage levels in violation of applicable emergency limits.

1.1.4. Loadings on transmission facilities in violation of applicable emergency limits.

1.1.5. Unacceptable loss of load based on regional and/or NERC criteria.

1.2. Compliance Monitoring Period and Reset Timeframe

The reset period is monthly.

1.3. Data Retention

The data retention period is three months.

2. Levels of Non-Compliance

2.1. The Transmission Operator did not inform the Reliability Coordinator of an IROL or an SOL that has become an IROL because of changed system conditions, and the actions they are taking to return the system to within limits, or

2.2. The Transmission Operator did not take corrective actions as directed by the Reliability Coordinator to return the system to within the IROL within 30 minutes. (See Table 1-TOP-007-0 below.)

2.3. The limit violation was reported to the Reliability Coordinator, who did not provide appropriate direction to the Transmission Operator, resulting in an IROL violation in excess of 30 minutes duration.

Table 1-TOP-007-0 IROL and SOL Reporting Levels of Non-Compliance

Percentage by which IROL or SOL that has become an IROL is exceeded*	Limit exceeded for more than 30 minutes, up to 35 minutes.	Limit exceeded for more than 35 minutes, up to 40 minutes.	Limit exceeded for more than 40 minutes, up to 45 minutes.	Limit exceeded for more than 45 minutes.
Greater than 0%, up to and including 5%	Level 1	Level 2	Level 2	Level 3
Greater than 5%, up to and including 10%	Level 2	Level 2	Level 3	Level 3
Greater than 10%, up to and including 15%	Level 2	Level 3	Level 3	Level 4
Greater than 15%, up to and including 20%	Level 3	Level 3	Level 4	Level 4
Greater than 20%, up to and including 25%	Level 3	Level 4	Level 4	Level 4
Greater than 25%	Level 4	Level 4	Level 4	Level 4

*Percentage used in the left column is the flow measured at the end of the time period (30, 35, 40, or 45 minutes).

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Response to Transmission Limit Violations**

2. **Number:** TOP-008-0

3. **Purpose:** To ensure Transmission Operators take actions to mitigate SOL and IROL violations.

4. **Applicability**

    4.1. Transmission Operators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.

R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.

R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **System Performance Under Normal (No Contingency) Conditions (Category A)**

2. **Number:** TPL-001-0

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0_R2.1 and TPL-001-0_R2.2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe
Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	June 03, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-0

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number**: TPL-004-0

3. **Purpose**: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** **Regional and Interregional Self-Assessment Reliability Reports**

2. **Number:** TPL-005-0

3. **Purpose:** To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall annually conduct reliability assessments of its respective existing and planned Regional Bulk Electric System (generation and transmission facilities) for:

R1.1. Current year:

R1.1.1. Winter.

R1.1.2. Summer.

R1.1.3. Other system conditions as deemed appropriate by the Regional Reliability Organization.

R1.2. Near-term planning horizons (years one through five). Detailed assessments shall be conducted.

R1.3. Longer-term planning horizons (years six through ten). Assessment shall focus on the analysis of trends in resources and transmission Adequacy, other industry trends and developments, and reliability concerns.

R1.4. Inter-Regional reliability assessments to demonstrate that the performance of these systems is in compliance with NERC Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0 and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting Adequacy and Security.

R2. The Regional Reliability Organization shall provide its Regional and Inter-Regional seasonal, near-term, and longer-term reliability assessments to NERC on an annual basis.

R3. The Regional Reliability Organization shall perform special reliability assessments as requested by NERC or the NERC Board of Trustees under their specific directions and criteria. Such assessments may include, but are not limited to:

R3.1. Security assessments.

R3.2. Operational assessments.

R3.3. Evaluations of emergency response preparedness.

R3.4. Adequacy of fuel supply and hydro conditions.

R3.5. Reliability impacts of new or proposed environmental rules and regulations.

R3.6. Reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the Adequacy of the interconnected Bulk Electric Systems in North America.

C. Measures

M1. The Regional Reliability Organization shall provide evidence to its Compliance Monitor that annual Regional and Inter-Regional assessments of reliability for seasonal, near-term, and longer-term planning horizons, and special assessments, were developed and provided as requested by other Regional Reliability Organizations or NERC.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Regional, Inter-Regional, and/or special reliability assessments were provided as requested, but were incomplete.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Regional, Inter-Regional, and/or special reliability assessments were not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Data From the Regional Reliability Organization Needed to Assess Reliability**
2. **Number:** TPL-006-0
3. **Purpose:** To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.
4. **Applicability:**
   - **4.1.** Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall provide, as requested (seasonally, annually, or as otherwise specified) by NERC, system data, including past, existing, and future facility and Bulk Electric System data, reports, and system performance information, necessary to assess reliability and compliance with the NERC Reliability Standards and the respective Regional planning criteria.

The facility and Bulk Electric System data, reports, and system performance information shall include, but not be limited to, one or more of the following types of information as outlined below:

R1.1. Electric Demand and Net Energy for Load (actual and projected demands and Net Energy for Load, forecast methodologies, forecast assumptions and uncertainties, and treatment of Demand-Side Management.)

R1.2. Resource Adequacy and supporting information (Regional assessment reports, existing and planned resource data, resource availability and characteristics, and fuel types and requirements.)

R1.3. Demand-Side resources and their characteristics (program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations.)

R1.4. Supply-side resources and their characteristics (existing and planned generator units, Ratings, performance characteristics, fuel types and availability, and real and reactive capabilities.)

R1.5. Transmission system and supporting information (thermal, voltage, and Stability Limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems.)

R1.6. System operations and supporting information (extreme weather impacts, Interchange Transactions, and Congestion impacts on the reliability of the interconnected Bulk Electric Systems.)

R1.7. Environmental and regulatory issues and impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation.)

Measures

M2. The Regional Reliability Organization shall provide evidence to its Compliance Monitor that it provided Regional system data, reports, and system performance information per Reliability Standard TPL-006-0_R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Requested Regional system data, reports, or system performance information were incomplete.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Requested Regional system data, reports, or system performance information were not provided.

D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Voltage and Reactive Control**

2. **Number:** VAR-001-0

3. **Purpose:**

   To ensure voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Generator Operators

   4.3. Purchasing-Selling Entities

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and MVAR flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.

R4. The Transmission Operator shall know the status of all transmission reactive power resources, including the status of voltage regulators and power system stabilizers.

R5. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

R6. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R7. Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.

R7.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R8. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R9. Each Generator Operator shall provide information to its Transmission Operator on the status of all generation reactive power resources, including the status of voltage regulators and power system stabilizers.

R9.1. When a generator's voltage regulator is out of service, the Generator Operator shall maintain the generator field excitation at a level to maintain Interconnection and generator stability.

R10. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

1200 — CYBER SECURITY

1. **Purpose**: To reduce risks to the reliability of the bulk electric systems from any compromise of critical cyber assets.
2. **Effective Period**: This urgent request standard will be in effect for one year from the date of NERC Board of Trustees adoption or until it is replaced by a permanent standard, whichever occurs first.
3. **Applicability:** These cyber security standards apply to entities performing various electric system functions, as defined in the functional model approved by the NERC Board of Trustees in June 2001. NERC is now developing standards and procedures for the identification and certification of such entities. Until that identification and certification is complete, these standards apply to the existing entities (such as control areas, transmission owners and operators, and generation owners and operators) that are currently performing the defined functions.

1201 — Cyber Security Policy

1. Requirement

1.1. The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall create and maintain a cyber security policy for the implementation of this standard.

1.2. The responsible entity shall assign a member of senior management with responsibility for leading and managing the entity's cyber security program. This person must authorize any deviation or exception from the requirements of this standard. Justification for any such deviation or exemption must be documented.

2. Measures

2.1. The responsible entity shall maintain its written cyber security policy stating the entity's commitment to protect critical cyber assets.

2.2. The responsible entity shall review the cyber security policy at least annually.

2.3. The current senior management official responsible for the cyber security program shall be identified by name, title, phone, address, and date of designation.

2.4. The responsible entity shall maintain documentation justifying any deviations or exemptions authorized by the current senior management official responsible for the cyber security program.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the following available for inspection by the compliance monitor upon request:

4.3.1. Written cyber security policy;

4.3.2. The name, title, address, and phone number of the current designated senior management official and the date of his or her designation; and

4.3.3. Documentation of justification for any deviations or exemptions.

5. Levels of Noncompliance

5.1. Level one:

5.1.1. A current senior management official was not designated for less than 30 days during a calendar year; or

5.1.2. A written cyber security policy exists but has not been reviewed in the last calendar year.

5.2. Level two: A current senior management official was not designated for 30 or more days, but less than 60 days during a calendar year.

5.3. Level three: A current senior management official was not designated for 60 or more days, but less than 90 days during a calendar year

5.4. Level four:

5.4.1. A current senior management official was not designated for more than 90 days during a calendar year; or

5.4.2. No cyber security policy exists.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1202 — Critical Cyber Assets

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall identify its critical cyber assets.

2. Measures

2.1. The responsible entity shall maintain a document identifying critical cyber assets.

2.2. The responsible entity shall review and update its critical cyber asset identification document at least annually or within 90 days of the addition or removal of any critical cyber assets.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the following available for inspection by the compliance monitor upon request:

4.3.1. List of critical cyber assets; and

4.3.2. Verification that necessary updates were made at least annually or within 90 days of the addition or removal of critical cyber assets.

5. Levels of Noncompliance

5.1. Level one: Document exists, but document was not updated with known changes within the 90-day period.

5.2. Level two: Document exists, but the document has not been updated or reviewed in the last 12 months.

5.3. Level three: (None specified.)

5.4. Level four: No document exists.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1203 — Electronic Security Perimeter

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall identify its electronic security perimeter(s).

2. Measures

2.1. The responsible entity shall maintain a document depicting the electronic security perimeter(s), all interconnected critical cyber assets, and all electronic access points to the interconnected environment(s). The document shall verify that all critical cyber assets are within the electronic security perimeter(s).

2.2. The responsible entity shall review and update its document referenced in 1203.2.1 at least annually or within 90 days of the modification of the network.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the following available for inspection by the compliance monitor upon request:

4.3.1. Document as described in 1203.2.1; and

4.3.2. Verification that necessary updates were made at least annually or within 90 days of a modification.

5. Levels of Noncompliance

5.1. Level one: Document exists, but document was not updated with known changes within the 90-day period.

5.2. Level two: Document exists, but the document has not been updated or reviewed in the last 12 months.

5.3. Level three: Document exists, but no verification that all critical assets are within the perimeter(s) described.

5.4. Level four: No document exists.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1204 — Electronic Access Controls

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall identify and implement electronic access controls for access to critical cyber assets within the electronic security perimeter.

2. Measures

2.1. The responsible entity shall maintain a document identifying the access controls and their implementation for each electronic access point to the electronic security perimeter(s).

2.2. The responsible entity shall review and update the documentation referenced in 1204.2.1 at least annually or within 90 days of the modification of the electronic security perimeter or the electronic access controls.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the following available for inspection by the compliance monitor upon request:

4.3.1. Document as described in 1204.2.1; and

4.3.2. Verification that necessary updates were made at least annually or within 90 days of a modification.

5. Levels of Noncompliance

5.1. Level one: Document exists, but document was not updated with known changes within the 90-day period.

5.2. Level two: Document exists, but the document has not been updated or reviewed in the last 12 months.

5.3. Level three: Document exists, but the document does not identify the electronic access controls for one or more access points.

5.4. Level four: No document exists.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1205 — Physical Security Perimeter

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall identify its physical security perimeter(s) for the protection of critical cyber assets.

2. Measures

2.1. The responsible entity shall maintain a document depicting the physical security perimeter(s) and all physical access points to every such perimeter. The document shall verify that all critical cyber assets are within the physical security perimeter(s).

2.2. The responsible entity shall review and update the document referenced in 1205.2.1 at least annually or within 90 days of the modification of the network.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the following available for inspection by the compliance monitor upon request:

4.3.1. Document as described in 1205.2.1; and

4.3.2. Verification that necessary updates were made at least annually or within 90 days of a modification.

5. Levels of Noncompliance

5.1. Level one: Document exists, but document was not updated with known changes within the 90-day period.

5.2. Level two: Document exists, but the document has not been updated or reviewed in the last 12 months.

5.3. Level three: Document exists, but no verification that all critical cyber assets are within the perimeter(s) described.

5.4. Level four: No document exists.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1206 — Physical Access Controls

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall identify and implement physical access controls for access to critical cyber assets within the physical security perimeter(s).

2. Measures

2.1. The responsible entity shall maintain a document identifying the access controls and their implementation for each physical access point to the physical security perimeter(s).

2.2. The responsible entity shall review and update the documentation referenced in 1206.2.1 at least annually or within 90 days of the modification of the physical security perimeter(s) or the physical access controls.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the following available for inspection by the compliance monitor upon request:

4.3.1. Document as described in 1206.2.1; and

4.3.2. Verification that necessary updates were made at least annually or within 90 days of a modification.

5. Levels of Noncompliance

5.1. Level one: Document exists, but document was not updated with known changes within the 90-day period.

5.2. Level two: Document exists, but the document has not been updated or reviewed in the last 12 months.

5.3. Level three: Document exists, but the document does not identify the physical access controls for one or more access points.

5.4. Level four: No document exists.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1207 — Personnel

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall identify all personnel, including contractors and service vendors, granted electronic or physical access to critical cyber assets.

2. Measures

2.1. The responsible entity shall maintain a list of all personnel granted access to critical cyber assets, including the specific electronic and physical access rights to the security perimeter(s).

2.2. The responsible entity shall review the document referred to in 1207.2.1 at least quarterly and update the document within 24 hours of any change.

2.3. The responsible entity shall conduct background screening of personnel consistent with the degree of access they are granted, in accordance with federal, state, provincial, and local laws.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the following available for inspection by the compliance monitor upon request:

4.3.1. Document as described in 1207.2.1;

4.3.2. Verification that necessary updates were made at least quarterly or within 24 hours of a modification; and

4.3.3. Verification that personnel background checks are being conducted consistent with access granted to them.

5. Levels of Noncompliance

5.1. Level one:

5.1.1. List of personnel with their access control rights list is available, but has not been updated or reviewed for more than three months but less than six months; or

5.1.2. One instance of personnel termination (employee, contractor or service vendor) in which the access control list was not updated within 24 hours.

5.2. Level two:

5.2.1. Access control rights list is available, but has not been updated or reviewed for more than 6 months but less than 12 months; or

5.2.2. More than one but not more than five instances of personnel termination (employee, contractor or service vendor) in which the access control list was not updated within 24 hours.

5.3. Level three:

5.3.1. Access control rights list is available, but does not include service vendors;

5.3.2. More than five instances of personnel termination (employee, contractor or service vendor) in which the access control list was not updated within 24 hours; or

5.3.3. No personnel background screening conducted.

5.4. Level four: Access control rights list does not exist.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1208 — Monitoring Physical Access

1. Requirements

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall monitor physical access to critical cyber assets 24 hours a day, 7 days a week.

2. Measures

2.1. The responsible entity shall maintain a document identifying its tools and procedures for physical access monitoring. This document shall verify that the tools and procedures are functioning and being used as planned.

2.2. The responsible entity shall document physical access to critical cyber assets via access records (e.g., logs). Access records shall be verified against the list of access control rights or controlled by video or other physical monitoring.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for six months. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the following available for inspection by the compliance monitor upon request:

4.3.1. Document as described in 1208.2.1;

4.3.2. Records of physical access to critical cyber assets; and

4.3.3. Demonstration that the list of access control rights is controlled by video or other physical monitoring.

5. Levels of Noncompliance

5.1. Level one: Monitoring is in place, but a gap in the logs or other measures exists for less than seven days.

5.2. Level two: Access not monitored to any critical cyber asset for less than one day.

5.3. Level three:

5.3.1. Access not monitored to any critical cyber asset for more than one day but less than one week; or

5.3.2. Log or other monitoring reveals access by personnel not approved on the access control list.

5.4. Level four: No monitoring of access exists.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1209 — Monitoring Electronic Access

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall monitor electronic access to critical cyber assets, 24 hours a day, 7 days a week.

2. Measures

2.1. The responsible entity shall maintain a document identifying electronic access monitoring tools and procedures. This document shall verify that the tools and procedures are functioning and being used as planned.

2.2. The responsible entity shall document electronic access to critical cyber assets via access records (e.g., logs). Access records shall be verified against the list of access control rights.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for six months. The compliance monitor shall keep audit records data for three years.

4.3. The responsible entity shall make the following available for inspection by the compliance monitor upon request:

4.3.1. Document as described in 1209.2.1;

4.3.2. Records of electronic access to critical cyber assets; and

4.3.3. Demonstration that the list of access control rights is verified.

5. Levels of Noncompliance

5.1. Level one: Monitoring is in place, but a gap in the access records exists for less than seven days.

5.2. Level two: Access not monitored to any critical cyber asset for less than one day.

5.3. Level three:

5.3.1. Access not monitored to any critical cyber asset for more than one day but less than one week; or

5.3.2. Access records reveal access by personnel not approved on the access control list.

5.4. Level four: No monitoring of access exists.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1210 — Information Protection

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall protect information associated with critical cyber assets and the policies and practices used to keep them secure.

2. Measures

2.1. The responsible entity shall maintain a document identifying the access limitations to sensitive information related to critical cyber assets. At a minimum, this document must address access to procedures, critical asset inventories, maps, floor plans, equipment layouts and configurations.

2.2. The responsible entity shall review and update the document referred to in 1210.2.1 as necessary and at least annually.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the document as described in 1210.2.1 available for inspection by the compliance monitor upon request.

5. Levels of Noncompliance

5.1. Level one: Document exists, but document has not been reviewed or updated in the last 12 months.

5.2. Level two: Document exists, but does not cover one of the specific items identified.

5.3. Level three: Document exists, but does not cover three of the specific items identified.

5.4. Level four: No document exists.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1211 — Training

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall train personnel commensurate with their access to critical cyber assets. The training shall address, at a minimum: the cyber security policy, physical and electronic access controls to critical cyber assets, the release of critical cyber asset information, potential threat incident reporting, and action plans and procedures to recover or re-establish critical cyber assets following a cyber security incident. Training shall be conducted upon initial employment and reviewed annually.

2. Measures

2.1. The responsible entity shall develop and maintain a company-specific cyber security training program that includes, at a minimum, the following required items:

2.1.1. The cyber security policy;

2.1.2. Physical and electronic access controls to critical cyber assets;

2.1.3. The release of critical cyber asset information;

2.1.4. Potential threat incident reporting; and

2.1.5. Action plans and procedures to recover or re-establish critical cyber assets following a cyber security incident.

2.2. The responsible entity shall maintain a document identifying all personnel who have access to critical cyber assets and the date of the successful completion of their training.

2.3. The responsible entity shall document that it has reviewed its training program at least annually.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the training documents described in 1211.2.1, -2.2, and -2.3 available for inspection by the compliance monitor upon request.

5. Levels of Noncompliance

5.1. Level one: Training program exists, but records of training either do not exist or reveal some key personnel not trained as required.

5.2. Level two: Training program exists, but does not cover one of the specific items identified.

5.3. Level three: Document exists, but does not cover two of the specific items identified.

5.4. Level four: No training program exists addressing critical cyber assets.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1212 — Systems Management

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall establish systems management policies and procedures for configuring and securing critical cyber assets. At a minimum, these policies and procedures shall address:

1.1. The use of effective password management that periodically requires changing of passwords, including default passwords for newly installed equipment;

1.2. The authorization and periodic review of computer accounts and access rights;

1.3. The disabling of unauthorized, invalidated, expired, or unused computer accounts and physical access rights;

1.4. The disabling of unused network services and ports;

1.5. Secure dial-up modem connections;

1.6. Firewall management;

1.7. Intrusion detection processes;

1.8. Security patch management;

1.9. The installation and update of anti-virus software;

1.10. The retention and review of operator logs, application logs, and intrusion detection logs; and

1.11. Identification of vulnerabilities and responses.

2. Measures

2.1. The responsible entity shall maintain a document identifying system management policies and procedures.

2.2. The responsible entity shall review and update the document referred to in 1212.2.1 as necessary and at least annually.

2.3. The system management policies and procedures document shall address all items in requirement 1212.1.

2.4. The responsible entity shall implement system management policies and procedures as described in the system management policies and procedures document.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the following available for inspection by the compliance monitor upon request:

4.3.1. Document as described in 1212.2.1; and

4.3.2. Verification that system management policies and procedures are being followed.

5. Levels of Noncompliance

5.1. Level one:

5.1.1. Document exists, but does not cover one of the specific items identified; or

5.1.2. The document has not been reviewed or updated in the last 12 months.

5.2. Level two: Document exists, but does not cover three of the specific items identified.

5.3. Level three: Document exists, but does not cover five of the specific items identified.

5.4. Level four: No document exists.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1213 — Test Procedures

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall establish test procedures and acceptance criteria to ensure that critical cyber assets installed or modified comply with the security requirements in this standard. Test procedures shall require that testing and acceptance be conducted in an isolated test environment.

2. Measures

2.1. The responsible entity shall maintain a document identifying test and acceptance criteria for the installation or modification of critical cyber assets.

2.2. The responsible entity shall maintain a document verifying that it has implemented the test and acceptance criteria.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the documents described in 1213.2.1 and -2.2 available for inspection by the compliance monitor upon request.

5. Levels of Noncompliance

5.1. Level one: Test procedures and acceptance criteria document exists, but has not been reviewed or updated within the last 12 months.

5.2. Level two: (None specified.)

5.3. Level three: (None specified.)

5.4. Level four: Test procedures and acceptance criteria document does not exist.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1214 — Electronic Incident Response Actions

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall define electronic incident response actions, including roles and responsibilities assigned by individual or job function.

2. Measures

2.1. The responsible entity shall maintain a document defining the electronic incident response action, including actions, roles and responsibilities.

2.2. The document in 1214.2.1 shall require that incidents involving critical cyber assets shall be reported to the electricity sector information sharing and analysis center in accordance with the *NERC-NIPC Indications, Analysis, Warnings Program Standard Operating Procedure*.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the document described in 1214.2.1 available for inspection by the compliance monitor upon request.

5. Levels of Noncompliance

5.1. Level one: Electronic incident response plan exists, but has not been reviewed or updated in the last 12 months.

5.2. Level two: (None specified.)

5.3. Level three:

5.3.1. Document exists, but does not assign responsibilities; or

5.3.2. Document exists, but does not require that incidents involving critical cyber assets shall be reported to the electricity sector information sharing and analysis center in accordance with the *NERC-NIPC Indications, Analysis, Warnings Program Standard Operating Procedure.*

5.4. Level four: No document exists.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed this urgent action standard.

1215 — Physical Incident Response Actions

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall define physical incident response actions, including roles and responsibilities assigned by individual or job function.

2. Measures

2.1. The responsible entity shall maintain a document defining the physical incident response action, including actions, roles and responsibilities.

2.2. The document in 1215.2.1 shall require that incidents involving physical assets used to protect critical cyber assets shall be reported to the electricity sector information sharing and analysis center in accordance with the *NERC-NIPC Indications, Analysis, Warnings Program Standard Operating Procedure*.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the document described in 1215.2.1 available for inspection by the compliance monitor upon request.

5. Levels of Noncompliance

5.1. Level one: Physical incident response plan exists, but has not been reviewed or updated in the last 12 months.

5.2. Level two: (None specified.)

5.3. Level three:

5.3.1. Document exists, but does not assign responsibilities; or

5.3.2. Document exists, but does not require that incidents involving physical assets used to protect critical cyber assets shall be reported to the electricity sector information sharing and analysis center in accordance with the *NERC-NIPC Indications, Analysis, Warnings Program Standard Operating Procedure.*

5.4. Level four: No document exists.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

1216 — Recovery Plans

1. Requirement

The entity performing the reliability authority, balancing authority, interchange authority, transmission service provider, transmission operator, generator, or load-serving entity function shall create action plans and procedures to recover or re-establish critical cyber assets following a cyber security incident. Each responsible entity shall exercise these plans at least annually. The plans and procedures shall define roles and responsibilities by individual or job function.

2. Measures

2.1. The responsible entity shall maintain a document defining the action plan and procedures used to recover or re-establish critical cyber assets following a cyber security event, including actions, roles and responsibilities.

2.2. The responsible entity shall maintain a document verifying that the action plan is exercised via drill at least annually.

3. Regional Differences

None identified.

4. Compliance Monitoring Process

4.1. The responsible entity shall demonstrate compliance through self-certification submitted to the compliance monitor annually. The compliance monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

4.2. The performance-reset period shall be one calendar year. The responsible entity shall keep data for three calendar years. The compliance monitor shall keep audit records for three years.

4.3. The responsible entity shall make the documents described in 1216.2.1 and -2.2 available for inspection by the compliance monitor upon request.

5. Levels of Noncompliance

5.1. Level one: Action plans and procedures exist, but have not been reviewed or updated in the last 12 months.

5.2. Level two: Action plans and procedures have not been exercised through a drill in the last 12 months.

5.3. Level three: Action plans and procedures do not define specific roles and responsibilities.

5.4. Level four: No action plans of procedures exist.

6. Sanctions

6.1. Sanctions will be letters only for noncompliance and shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this urgent action standard for reference). No financial penalties will be assessed with this urgent action standard.

Sanctions Table

The following is an approved matrix of compliance sanctions developed by the Compliance Subcommittee as part of the NERC Compliance Enforcement Program and was approved by the NERC Board of Trustees.

Levels of noncompliance are tied to this matrix. The matrix is divided into four levels of increasing noncompliance vertically and the number of violations in a defined period at a given level horizontally.

In the enforcement matrix, note that there are three sanctions that can be used: a letter, a fixed fine, and a $$ per MW fine.

Letter

The letter is a sanction used to notify company executives, Regional officers, and regulators when an entity is non-compliant. The distribution of the letter varies depending on the severity of the noncompliance. It is used first to bring noncompliance to light to people who can influence the operation to become compliant.

- Letter (A) — Letter to the entity's vice president level or equivalent informing the entity of noncompliance, with copies to the data reporting contact, and the entity's highest ranking Regional Council representative.
- Letter (B) — Letter to the entity's chief executive officer or equivalent, with copies to the data reporting contact, the entity's highest ranking Regional Council representative, and the vice president over the area in which noncompliance occurred.
- Letter (C) — Letter to the entity's chief executive officer and chairman of the board, with copies to the NERC president, regulatory authorities having jurisdiction over the non-compliant entity (if requested by such regulatory authorities), the data reporting contact, the entity's highest ranking Regional Council representative, and the vice president over the area in which non-compliance occurred.

Fixed Dollars

This sanction is used when a letter is not enough and a stronger message is desired. Fixed dollars are typically assigned as a one-time fine that is ideal for measures involving planning-related standards. Many planning actions use forward-looking assumptions. If those assumptions prove wrong in the future, yet they are made in good faith using good practices, entities should not be harshly penalized for the outcome.

Dollars per MW

Dollars per MW sanctions are oriented toward operationally based standards. The MW can be load, generation, or flow on a line. Reasonableness of a sanction needs to be figured into assessing $/MW penalties. Assessing large financial penalties is not the goal, but sending a message with proper emphasis on $$$ can be controlled with the multiplier.

Occurrence Period Category	Number of Violations in Occurrence Period at a Given Level			
1st Period of Violations (Fully Compliant Last Period)	1	2	3	4 or more
2nd Consecutive Period of Violations		1	2	3 or more
		$ Sanction from Table; Letter (C) only if Letter (B) previously sent		
3rd Consecutive Period of Violations			1	2 or more
			$ Sanction from Table; Letter (C) only if Letter (B) previously sent	
4th or greater Consecutive Period of Violations				1
				$ Sanction from Table; Letter (C)

Level of Non-Compliance	Sanctions Associated with Non-compliance			
Level 1	Letter (A)	Letter (A)	Letter (B) and $1,000 or $1 Per MW	Letter (B) and $2,000 or $2 Per MW
Level 2	Letter (A)	Letter (B) and $1,000 or $1 Per MW	Letter (B) and $2,000 or $2 Per MW	Letter (B) and $4,000 or $4 Per MW
Level 3	Letter (B) and $1,000 or $1 Per MW	Letter (B) and $2,000 or $2 Per MW	Letter (B) and $4,000 or $4 Per MW	Letter (B) and $6,000 or $6 Per MW
Level 4	Letter (B) and $2,000 or $2 Per MW	Letter (B) and $4,000 or $4 Per MW	Letter (B) and $6,000 or $6 Per MW	Letter (B) and $10,000 or $10 Per MW

Interpreting the Tables:

- These tables address penalties for violations of the same measure occurring in consecutive compliance reporting periods.
- If a participant has non-compliant performance in consecutive compliance reporting periods, the sanctions applied are more punitive.

These definitions have been posted and balloted along with the cyber security standards, but will not be restated in the cyber security standards. Instead, they will be included in a separate “Definitions” section containing definitions relevant to all standards that NERC develops.

DEFINITIONS

Critical Cyber Assets: Those computers, including installed software and electronic data, and communication networks that support, operate, or otherwise interact with the bulk electric system operations. This definition currently does not include process control systems, distributed control systems, or electronic relays installed in generating stations, switching stations and substations.

Electronic Security Perimeter: The border surrounding the network or group of sub-networks (the “secure network”) to which the critical cyber assets are connected.

Physical Security Perimeter: The border surrounding computer rooms, telecommunications rooms, operations centers, and other clearly defined locations in which critical cyber assets are housed and access is controlled.

Cyber Security Incident: Any event or failure (malicious or otherwise) that disrupts the proper operation of a critical cyber asset.

Incident Response: Responding to, and reporting a cyber security incident.

Compliance Monitor: The organization responsible for monitoring compliance with this standard in accordance with the NERC compliance enforcement program.

Glossary of Terms Used in Reliability Standards

February 7, 2006

Term	Acronym	Definition
Adequacy		The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority		A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact		The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection. (From Balance Resources and Demand standard.)
Agreement		A contract or arrangement, either written or verbal and sometimes enforceable by law.
Altitude Correction Factor		A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.
Ancillary Service		Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)
Anti-Aliasing Filter		An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error	ACE	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.
Automatic Generation Control	AGC	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.
Available Transfer Capability	ATC	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area		The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Term	Acronym	Definition
Base Load		The minimum amount of electric power delivered or required over a given period at a constant rate.
Blackstart Capability Plan		A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Bulk Electric System		As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.
Burden		Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Capacity Benefit Margin	CBM	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Capacity Emergency		A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading		The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
Clock Hour		The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration		Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor		The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Congestion Management Report		A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.

Term	Acronym	Definition
Constrained Facility		A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contingency		The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Reserve		The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Contract Path		An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.
Control Performance Standard	CPS	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Corrective Action Plan		A list of actions and an associated timetable for implementation to remedy a specific problem.
Curtailment		A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Curtailment Threshold		The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Demand		1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management	DSM	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Direct Control Load Management	DCLM	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.
Dispersed Load by Substations		Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor	DF	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).
Distribution Provider		Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.

Term	Acronym	Definition
Disturbance		1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard	DCS	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.
Dynamic Interchange Schedule or Dynamic Schedule		A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Dynamic Transfer		The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.
Economic Dispatch		The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electrical Energy		The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Element		Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Emergency or BES Emergency		Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating		The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Energy Emergency		A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Equipment Rating		The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.

Term	Acronym	Definition
Facility		A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)
Facility Rating		The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault		An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk		The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand		That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service		The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover		An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate		A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.
Forced Outage		1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias		A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.
Frequency Bias Setting		A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Deviation		A change in Interconnection frequency.
Frequency Error		The difference between the actual and scheduled frequency. (F_A – F_S)
Frequency Regulation		The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.

Term	Acronym	Definition
Frequency Response		(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).
Generator Operator		The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner		Entity that owns and maintains generating units.
Generator Shift Factor	GSF	A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
Generator-to-Load Distribution Factor	GLDF	The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Host Balancing Authority		1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value		Data measured on a Clock Hour basis.
Inadvertent Interchange		The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. $(I_A – I_S)$
Independent Power Producer	IPP	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc.	IEEE	
Interchange Distribution Calculator	IDC	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.
Interchange Schedule		An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction		An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.

Term	Acronym	Definition
Interchange Transaction Tag or Tag		The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service		A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection		When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection Reliability Operating Limit	IROL	The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.
Intermediate Balancing Authority		A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities
Interruptible Load or Interruptible Demand		Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.
Joint Control		Automatic Generation Control of jointly owned units by two or more Balancing Authorities.
Limiting Element		The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load		An end-use device or customer that receives power from the electric system.
Load Shift Factor	LSF	A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored flowgate.
Load-Serving Entity		Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Misoperation		▪ Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. ▪ Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). ▪ Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

Term	Acronym	Definition
Native Load		The end-use customers that the Load-Serving Entity is obligated to serve.
Net Actual Interchange		The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load		Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule		The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange		The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service		Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.
Non-Firm Transmission Service		Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve		1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Rating		The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Off-Peak		Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak		Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service	OASIS	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff	OATT	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.

Term	Acronym	Definition
Operating Plan		A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.
Operating Procedure		A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process		A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve		That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve – Spinning		The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Reserve – Supplemental		The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Voltage		The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Overlap Regulation Service		A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.

Term	Acronym	Definition
Peak Demand		1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period		The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Planning Authority		The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Point of Delivery	POD	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt	POR	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Point to Point Transmission Service	PTP	The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Pro Forma Tariff		Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.
Protection System		Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.
Pseudo-Tie		A telemetered reading or value that is updated in real time and used as a “virtual” tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
Purchasing-Selling Entity		The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Ramp Rate or Ramp		(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions		The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate
Rating		The operational limits of a transmission system element under a set of specified conditions.

Term	Acronym	Definition
Reactive Power		The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power		The portion of electricity that supplies energy to the load.
Reallocation		The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.
Real-time		Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Receiving Balancing Authority		The Balancing Authority importing the Interchange.
Regional Reliability Organization		1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.
Regional Reliability Plan		The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
Regulating Reserve		An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulation Service		The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Coordinator		The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Coordinator Area		The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Area		The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

Term	Acronym	Definition
Reliability Coordinator Information System	RCIS	The system that Reliability Coordinators use to post messages and share operating information in real time.
Remedial Action Scheme	RAS	See “Special Protection System”
Reportable Disturbance		Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority’s or reserve sharing group’s most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.
Reserve Sharing Group		A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority’s use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.
Resource Planner		The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
Response Rate		The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Right-of-Way (ROW)		A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Scenario		Possible event.
Schedule		(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency		60.0 Hertz, except during a time correction.
Scheduling Entity		An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path		The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority		The Balancing Authority exporting the Interchange.
Sink Balancing Authority		The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)

Term	Acronym	Definition
Source Balancing Authority		The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)
Special Protection System (Remedial Action Scheme)		An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
Spinning Reserve		Unloaded generation that is synchronized and ready to serve additional demand.
Stability		The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
Stability Limit		The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Supervisory Control and Data Acquisition	SCADA	A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service		A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.
Surge		A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.
Sustained Outage		The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System		A combination of generation, transmission, and distribution components.

Term	Acronym	Definition
System Operating Limit		The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator		An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.
Telemetering		The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating		The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line		A circuit connecting two Balancing Authority Areas.
Tie Line Bias		A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error		The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction		An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.
TLR Log		Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC web site.
Total Transfer Capability	TTC	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.

Term	Acronym	Definition
Transaction		See Interchange Transaction.
Transfer Capability		The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not g*enerally equal to the transfer capability from "Area B" to "Area A."
Transfer Distribution Factor		See Distribution Factor.
Transmission		An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission Constraint		A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer		1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line		A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator		The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
Transmission Owner		The entity that owns and maintains transmission facilities.
Transmission Planner		The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
Transmission Reliability Margin	TRM	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Service		Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider		The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.

Term	Acronym	Definition
Vegetation		All plant material, growing or not, living or dead.
Vegetation Inspection		The systematic examination of a transmission corridor to document vegetation conditions.
Wide Area		The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.

Effective until the Balance Resources and Demand Reliability Standard is approved, provided ERCOT remains a single Control Area Interconnection.

Waiver Request – Control Performance Standard 2

Organization

ERCOT

Operating Policy

ERCOT requests a waiver from Policy 1, "Generation Control and Performance," Section E, "Performance Standard" as follows:

Standards

1.2. **Control Performance Standard (CPS2)**. The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10}. See the "Performance Standard Training Document," Section B.1.1.2 for the methods for calculating L_{10}.

Requirements

2. **Control Performance Standard (CPS) Compliance**. Each CONTROL AREA shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90% (see the "Performance Standard Training Document," Section C).

Explanation

ERCOT requests a waiver from the CPS2 Standards and Requirements listed above for the following reasons:

1. On July 31, 2001, the ERCOT Interconnection began operating as a single CONTROL AREA, asynchronously connected via two DC ties to the Eastern Interconnection. At that time, ERCOT changed from the traditional tie-line bias generation control algorithms in which ten CONTROL AREAS participated, to a single 15-minute interval competitive balancing energy market and a frequency control system that regulates around the balancing energy schedule on two-to-four-second intervals. ERCOT requests that the Operating Committee reconsider CPS2 to ensure it is feasible under this new type of market-based control.

   If the Operating Committee believes that the CPS2 is feasible, then ERCOT would suggest that Policy 1 (or the appropriate Compliance document) provide for a "test period" of six months to allow CONTROL AREAS making such a transition the opportunity to test new control algorithms *provided* they can show that reliability is not degraded during that period. ERCOT also believes that its L_{10} may not be appropriate as it is less that half of the L_{10} of another NERC CONTROL AREA of similar load size.

2. The ERCOT Interconnection is now a single CONTROL AREA asynchronously connected to the Eastern Interconnection, and cannot create inadvertent power flows or frequency errors in other CONTROL AREAS. Therefore, the ISO questions whether the CPS2 Standard is necessary or even beneficial for such asynchronous operation. ERCOT is currently performing a study that compares its single CONTROL AREA performance against that of the former ten CONTROL AREA

operations. Initial results of that study show that while the ten CONTROL AREAS *individually* met CPS2 standards, the *aggregate* CPS2 performance of the ten CONTROL AREAS did not, and was actually below that of the current single CONTROL AREA.

Current Operating Reliability

ERCOT does not believe that Frequency control within its new single CONTROL AREA INTERCONNECTION is less reliable as a result of non-compliance with the CPS2 Standard following its conversion. ERCOT Interconnection frequency control has been, and continues to be, very reliable since that conversion.

The table below shows ERCOT's CPS2 performance for August through December 2000 as an INTERCONNECTION with ten Control Areas. The average CPS2 compliance was 74.82%. CPS2 compliance for ERCOT as a single control area for August 2001 was 83.88%, an improvement of approximately nine percentage points.

Single Control Area Frequency Performance

	% of Frequency Data Available	Supplier Of Frequency Data	Single Control Area CPS1 %	CPS2 %	Average of Absolute 1 min Averages Freq Deviation	Average of Absolute 10 min Averages Freq Deviation
August-00	79	ERCOT	140.99	76.50	0.011978483	0.008299971
September-00	100	ERCOT	134.89	76.02	0.012366	0.009495
September-00	100	REIT HLP	135.91	77.01	0.012221795	0.008443165
October-00	23	ERCOT	199.68	76.90	0.013910426	0.00857111
October-00	100	REIT HLP	114.01	78.58	0.014621429	0.008120248
November-00	65	ERCOT	105.19	67.20	0.015061531	0.010523159
December-00	60	ERCOT	192.59	72.60	0.013428052	0.009330552
Average (See Note 1)			134.71	74.82	0.013439915	0.009062032
August-01	None (See Note 2)	None (See Note 2)	127.30	83.88		

Note 1: Weighted Average Based on ERCOT for August, September November and December and REIT for October.
Note 2: From ERCOT CPS report. ERCOT is working on providing frequency data for August 2001.

Waiver Request – Energy Flow Information

Approved by Operating Committee

July 16 – 17, 2003

Organization

The Control Area participants of:

- Midwest ISO

Operating Policy

The CONTROL AREA participants request approval of this Waiver to implement a proposed multi-Control Area Energy Market, simplify TRANSACTION information requirements for market participants, and provide a means for providing Reliability Coordinators with appropriate information for reliability analysis, curtailments, reloads, reallocations, and Network and Native Load (NNL) redispatch requirements.

The participants are requesting a Waiver of specific provisions of NERC Policy 3, "Interchange," to accommodate a Multi-Control Area Energy Market. This waiver would also apply in the event that Control Areas in the RTO are combined into fewer Control Areas or into one Control Area. This wavier is required to realize the benefits of a LMP market operation in the RTO Area while increasing the level of granularity of information provided to the NERC Transmission Loading Relief Process. It is understood that the level of granularity of information provided to Reliability Coordinators must not be reduced or reliability will be negatively impacted. The RTO participants propose the use of the concepts contained within the PJM/MISO paper, "Managing Congestion to Address Seams," to meet the requirements specified in Policy 3.

The following specific sections of NERC Policy 3, Version 5.1, "Interchange," are affected by the RTO Scheduling Process proposed in this Waiver request:

Requirements

Policy 3

- 3A 2.1 – Application to Transactions

Explanation

Policy 3 currently requires that several different types of transactions be tagged; specifically, it requires that any transactions involving Control Area to Control Area transfers must be tagged in order that Reliability Coordinators may review them as necessary to ensure system reliability.

The Midwest ISO intends to begin operating a multi-Control Area Energy Market in the near future. In so doing, the Midwest ISO will be scheduling net energy transfers between their various Control Area members based on a dynamically calculated, security-constrained economic dispatch. Bilateral transactions and transactions into or out of the RTO will continue to be tagged as appropriate. Net Control Area interchanges resulting from the market dispatch will simultaneously sum to zero within the MISO market. These market dispatch instructions do not correspond to traditional bilateral transactions between Control Areas. Instead, they can be viewed as a method to economically dispatch all generation within the Midwest ISO market. Each Control Area's net interchange resulting from market dispatch is matched simultaneous with all the other Control Areas in the market. Rather than a specific Control Area assigned to receive this net market interchange, all Control Areas net interchanges in the market will be adjusted to sum to zero. Tagging this market interchange into bilateral transactions would be arbitrary and not accurate. Therefore, the Midwest ISO proposes that rather than supply Reliability Coordinators with tags, they instead be allowed to provide Reliability Coordinators with equivalent information that allows the same analyses and procedures to operate as would exist if tags had been entered.

Under this proposal, the Midwest ISO will establish a set of Coordinated Flowgates, which will be determined through the use of several studies, that represents all flowgates significantly impacted by the Midwest ISO's operation of their Energy Market. Further, the Midwest ISO will provide Reliability Coordinators the following information every 15 minutes:

- Total Flows attributed to Midwest ISO market operations for all Coordinated Flowgates
- Flows attributed to Midwest ISO NNL for all Coordinated Flowgates
- Flows attributed to Midwest ISO Economic Dispatch for all Coordinated Flowgates

This information will be provided for both current hour and next hour, and will be used to communicate to Reliability Coordinators the amount of flows to be considered as the result of firm and non-firm service on the various Coordinated Flowgates.

Additionally, every hour the Midwest ISO will submit to Reliability Coordinators a set of data describing the marginal units and associated participation factors for generation within the Midwest ISO market footprint. This data will at a minimum be supplied for imports to and exports from the market area, and will contain as much information as is determined to be necessary to ensure system reliability. This data will be used by Reliability Coordinators to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

Finally, the Midwest ISO will submit for each of its Control Areas estimated Interchange and Load for each hour of the day. This will be submitted on a day-ahead basis as well as an hour ahead basis. This data will be used by Reliability Coordinators to perform forward-looking security analyses.

Current Operating Reliability Implications

There are no reliability implications from this waiver.

Policy Conditions for Waiver Recommendation

Policy 3A.2.1

Application to TRANSACTIONS. All INTERCHANGE TRANSACTIONS and certain INTERCHANGE SCHEDULES shall be tagged. In addition, intra-CONTROL AREA transfers using Point-to-Point Transmission Service[1] shall be tagged. This includes:

- INTERCHANGE TRANSACTIONS (those that are between CONTROL AREAS).
- TRANSACTIONS that are entirely within a CONTROL AREA.
- DYNAMIC INTERCHANGE SCHEDULES (tagged at the expected average MW profile for each hour). (Note: a change in the hourly energy profile of 25% or more requires a revised tag.)
- INTERCHANGE TRANSACTIONS for bilateral INADVERTENT INTERCHANGE payback (tagged by the SINK CONTROL AREA).
- INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins (tagged by the SINK CONTROL AREA). **[See also, Policy 1E2 and 2.1, "Disturbance Control Standard"]**

Conditions:

The Midwest ISO must provide equivalent information regarding their market operations to Reliability Authorities as would be extracted from a transaction tag. Specifically, the Midwest ISO must provide

1.) Flows on significantly impacted flowgates, with indications as to firmness of those flows, in order that curtailments, reload, and reallocations may be directed by Reliability Coordinators as needed

2.) Marginal Units within the market footprint, in order that Reliability Coordinators may evaluate impacts of potential changes in dispatch within the market footprint

3.) Control Area Interchange and Load forecasts, in order that Reliability Coordinators may analyze the interconnected transmission system on a proactive basis

[1] This includes all "grandfathered" and other "non-888" Point-to-Point Transmission Service

Approved by Operating Committee.

March 23–25, 2004

Waiver Request – Enhanced Congestion Management (Curtailment/Reload/Reallocation)

Organization

The control area participants of:

- Midwest ISO, Inc.
- PJM Interconnection, L.L.C.

Operating Policy

The control area participants request approval of this waiver to implement a proposed multi-Control Area Energy Market, simplify TRANSACTION information requirements for market participants, and provide a means for providing Reliability Coordinators with appropriate information for security analysis and curtailments/reloads/reallocations and redispatch requirements.

The participants are requesting a waiver of specific provisions of the following NERC policies and appendices to accommodate a Multi-Control Area Energy Market.

This waiver would also apply in the event that applicant control areas are combined into fewer control areas or into one control area. This waiver is required to realize the benefits of a LMP market operation while increasing the level of granularity of information provided to the NERC Transmission Loading Relief Procedure. The applicant control areas propose the use of the concepts contained within the PJM/MISO paper, "Managing Congestion to Address Seams," to meet the requirements specified in Policy 9 and its related appendixes.

The processes proposed in this waiver request affect the following specific sections of NERC Policy 9:

- **Appendix 9C1B.C (How the IDC Handles Reallocation)**,
- **Appendix 9C1B.C Attachment B – Timing Requirements (IDC Calculations and Reporting Requirements)**, and
- **Appendix 9C1.G (Transaction Curtailment Formula)**
- Appendix 9C1B "Interchange Transaction Reallocation During TLR Levels 3a and 5a"

For the purposes of clarity, this waiver describes many actions as those of the "RTO." It should be noted that "RTO" refers to the market-operating entity in which the applicant control areas participate. Associated with this waiver are two distinct entities: 1.) Midwest ISO, and 2.) PJM Interconnection.

Assignment of Sub-Priorities

Requirements

Policy 9 – Appendix 9C1B

- 9C1B.C
- 9C1B.C.Attachment B

Explanation

The **"IDC Calculations and Reporting Requirements"** section of **Appendix 9C1B.C, Attachment B – Timing Requirements of Policy 9** states that "In a TLR Level 3a the INTERCHANGE TRANSACTIONS using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status."

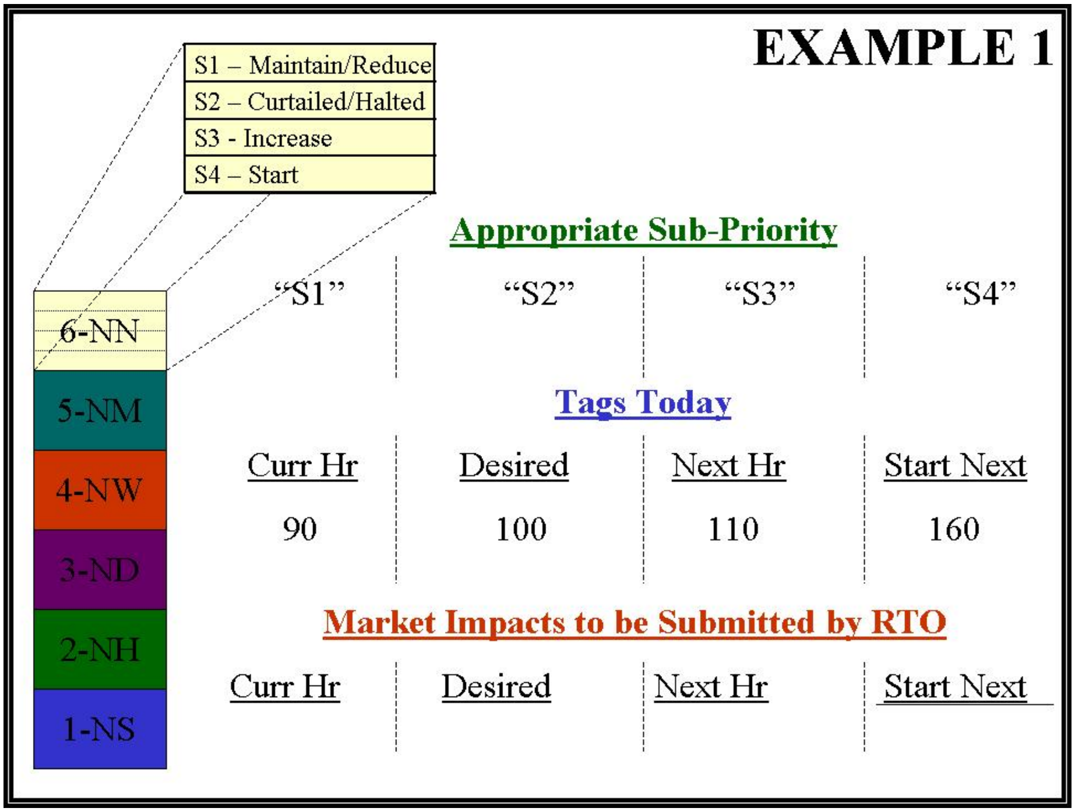
The RTO intends to use a "Market Flow Calculation" methodology to calculate the amount of energy flowing across all facilities included in the RTO's "Coordinated Flowgate List"[1] that is associated with the operation of the RTO market. This energy is identified as "market flow".

These market flow impacts for current hour and next hour will be separated into their appropriate priorities[2] and provided to the IDC by the RTO. The market flows will then be represented and made available for curtailment under the appropriate TLR Levels.

Even though these market flow impacts (separated into appropriate priorities) will not be represented by conventional "tags", the impacts and their desired levels will still be provided to the IDC for current hour and next hour. Therefore, the RTO proposes that for the purposes of reallocation, a sub-priority (S1 thru S4) be assigned to these market flow impacts by the NERC IDC, using the same parameters as would be used if the impacts were in fact tagged transactions — as detailed in NERC **Policy 9, Appendix 9C1, Attachment B – Timing Requirements (IDC Calculations & Reporting Requirements)**. *See Example 1 Below*

[1] The RTO will conduct sensitivity studies to determine which external flowgates (outside the RTO's footprint) are significantly impacted by the market flows of the RTO's control zones (currently the control areas that exist today in the IDC). The RTO will perform the 4 studies (described in the MISO/PJM Paper "Managing Congestion to Address Seams" White Paper Version 3.2) to determine which external flowgates the RTO will monitor and help control. An external flowgate selected by one of these studies will be considered a Coordinated Flowgate (CF).

[2] See the PJM/MISO Paper "Managing Congestion to Address Seams" for details on how these priorities will be assigned


EXAMPLE 1
S1 – Maintain/Reduce
S2 – Curtailed/Halted
S3 - Increase
S4 – Start
6-NN
5-NM
4-NW
3-ND
2-NH
1-NS
Appropriate Sub-Priority
"S1"
"S2"
"S3"
"S4"
Tags Today
Curr Hr
Desired
Next Hr
Start Next
90
100
110
160
Market Impacts to be Submitted by RTO
Curr Hr
Desired
Next Hr
Start Next

Pro Rata Curtailment of Non-Firm Market Flow Impacts

Requirements

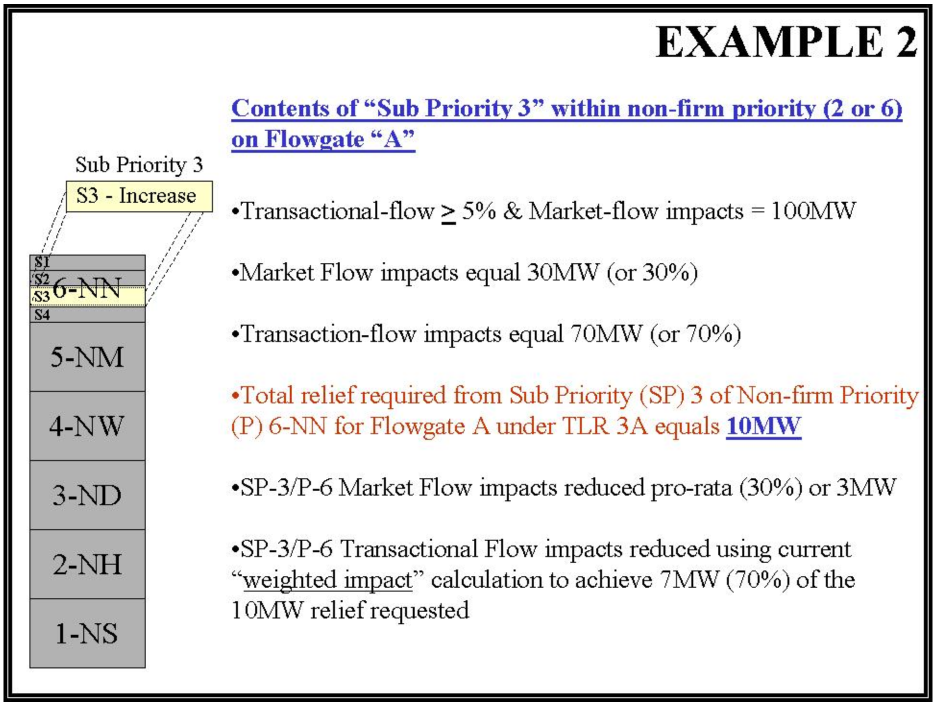
- **Appendix 9C1.G** (Transaction Curtailment Formula)

Explanation

NERC Policy 9, Appendix 9C1.G (Transaction Curtailment Formula) details the formula used to apply a weighted impact to each non-firm tagged transaction (Priorities 1 thru 6) for the purposes of curtailment by the IDC. For the purpose of curtailment, we propose that the non-firm market flow impacts (Priorities 1 thru 6) submitted to the IDC by the RTO be curtailed pro rata as is done for INTERCHANGE TRANSACTIONS using firm transmission service. This is because several of the values needed to assign a weighted impact using the process listed in **Policy 9 Appendix 9C1.G (Transaction Curtailment Formula)** will not be available:

- Distribution Factor (no tag to calculate this value from)
- Impact on Interface value (cannot be calculated without Distribution Factor)
- Impact Weighting Factor (cannot be calculated without Distribution Factor)
- Weighted Maximum Interface Reduction (cannot be calculated without Distribution Factor)
- Interface Reduction (cannot be calculated without Distribution Factor)
- Transaction Reduction (cannot be calculated without Distribution Factor)

While the non-firm market flow impacts submitted to the IDC would be curtailed pro rata under this proposal, the impacting non-firm tagged transactions could still use the existing processes to assign the weighted impact value. “Example 2” (below) illustrates how this would be accomplished.



NNL Calculation

Requirements

- **Appendix 9C1.F** (Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service)
- **Parallel Flow Calculation Procedure Reference Document – Section C** (Calculation Method)

Explanation

Policy 9 – Appendix 9C1.F and the **Parallel Flow Calculation Procedure Reference Document – Section C** currently require that the “Per Generator Method Without Counter Flow” methodology be utilized to calculate the portion of parallel flows on any Constrained Facility due to Network Integration (NI) transmission service and service to Native Load (NL) of each control area.

The RTO intends to use a “Market Flow Calculation” methodology to calculate the portion of parallel flows on all facilities included in the RTO’s “Coordinated Flowgate List”[3] due to NI service or service to NL of each control area.

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[3] The RTO will conduct sensitivity studies to determine which external flowgates (outside the RTO’s footprint) are significantly impacted by the market flows of the RTO’s control zones (currently the control areas that exist today in the IDC). The RTO will perform the four studies (described in the MISO/PJM paper “Managing Congestion to Address Seams,” Version 3.2) to

The Market Flow Calculation differs from the Per Generator Method in the following ways:

- The contribution from all market area generators will be taken into account.
- In the Per Generator Method, only generators having a GLDF greater than 5% are included in the calculation. Additionally, generators are included only when the sum of the maximum generating capacity at a bus is greater than 20 MW. The market flow calculations will use all positively impacting flows down to 0% with no threshold. Counter flows will not be included in the market flow calculation.
- The contribution of all market area generators is based on the present output level of each individual unit.
- The contribution of the market area load is based on the present demand at each individual bus.

By expanding on the Per Generator Method, the market flow calculation evolves into a methodology very similar the "Per Generator Method" method, while providing granularity on the order of the most granular method developed by the IDC Granularity Task Force. Counter flows are also calculated and tracked in order to account for and recognize that the either the positive market flows may be reduced or counter flows may be increased to provide appropriate relief on a flowgate. Under this proposal, the use of real-time values in concert with the market flow calculation effectively implements the most accurate and detailed method of the six IDC granularity options considered by the NERC IDC Granularity Task Force.

Units assigned to serve a market area's load do not need to reside within the RTO's market area footprint to be considered in the market flow calculation. However, units outside of the RTO's market area will not be considered when those units will have tags associated with their transfers.

These NNL values will be provided to the IDC to be included and represented with the calculated NNL values of all non-RTO control areas for the purposes identifying and obtaining required NNL relief across a flowgate in congestion under a TLR Level 5A/5B.

5% Curtailment Threshold

Requirements

- **Appendix 9C1B –** Item **A.2**

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determine which external flowgates the RTO will monitor and help control. An external flowgate selected by one of these studies will be considered a Coordinated Flowgate (CF).

Explanation

Policy 9 – Appendix 9C1B – Item A.2 states that "Only those INTERCHANGE TRANSACTIONS at or above the Curtailment Threshold for which a TLR 2 or higher is called are affected by the Reallocation procedure." The curtailment threshold stated in this section is "5%".

The RTO intends to use a "Market Flow Calculation" methodology to calculate the amount of energy flowing across all facilities included in the RTO's "Coordinated Flowgate List"[4] that is associated with the operation of the RTO Market. This energy is identified as "Market Flow"

The RTO intends to provide to the IDC any market flows with an impact of greater than 0% on a coordinated flowgate. These market flows will then be represented and made available for curtailment under the appropriate TLR Levels. Hence, for the purposes of curtailment and reallocation, the RTO proposes that the impact threshold the RTO will observe for its market flows across any flowgate in the RTO Coordinated Flowgate List will be **0%** instead of **5%.**

The reason for this is that because of the size and scope of a large non-tagged energy market, such as the multi-control area market that the RTO is proposing, an impact of less than 5% on a flowgate could still represent a large amount of the total capacity of that flowgate. Therefore, to limit the Curtailment Threshold on these market flows to 5% could result in a Reliability Coordinator's inability to obtain the amount of relief that is needed to prevent the flowgate from exceeding its operating limits.

Below is an example of how a market flow curtailment threshold of less than 5% could substantially contribute to congestion on a flowgate:

Example:

- Energy market flows of 1,000 MW impact Flowgate A by 4% — or 40 MW
- Flowgate A operating limit is 100 MW
- Fully 40% of the flow across Flowgate A is not identified and represented in the IDC, and therefore not available for curtailment under the TLR process.

Current Operating Reliability

There are no reliability implications from this waiver.

[4] The RTO will conduct sensitivity studies to determine which external flowgates (outside the RTO's footprint) are significantly impacted by the market flows of the RTO's control zones (currently the control areas that exist today in the IDC). The RTO will perform the 4 studies (described in the MISO/PJM "Managing Congestion to Address Seams" Whitepaper Version 3.2) to determine which external flowgates the RTO will monitor and help control. An external flowgate selected by one of these studies will be considered a Coordinated Flowgate (CF).

Approved by Operating Committee

July 16 – 17, 2003

Waiver Request – Enhanced Scheduling Agent

Organization

The Control Area participants of:

- Midwest ISO

Operating Policy

The CONTROL AREA participants request approval of this Waiver to implement a proposed RTO Scheduling Process to meet the RTO obligations under Order 2000, simplify TRANSACTION information requirements for market participants, reduce the number of parties with which CONTROL AREA operators must communicate, and provide a common means to tag TRANSACTIONS within and between RTOs.

The participants are requesting a Waiver of specific provisions of NERC Policy 3, "Interchange," to accommodate a RTO Scheduling Process. The RTO participants propose the following definition of a ENHANCED SCHEDULING AGENT:

ENHANCED SCHEDULING AGENT. A function with the authority to act on behalf of one or more CONTROL AREAS for INTERCHANGE SCHEDULE implementation including creation, confirmation, approval, check-out and associated INADVERTENT INTERCHANGE accounting.

The following specific sections of NERC Policy 3, Version 4, "Interchange," are affected by the RTO Scheduling Process proposed in this Waiver request:

Policy 3

- 3A 4 – Interchange Transaction Implementation (Assessment)
- 3A 6 – Interchange Transaction Implementation (Implementation)
- 3B 4 – Interchange Schedule Implementation (Confirmation)

Explanation

The ENHANCED SCHEDULING AGENT would be the single point of contact for all external, non-participating CONTROL AREAS or other SCHEDULING AGENTS with respect to scheduling INTERCHANGE into, out of, or through the RTO. Through TRANSACTIONS would be handled with the ENHANCED SCHEDULING AGENT acting as the single point of contact between each participating CONTROL AREA similar to an ADJACENT CONTROL AREA. Into or Out Of TRANSACTIONS would be handled with the ENHANCED SCHEDULING AGENT acting as the SINK or SOURCE CONTROL AREA, respectively. This reduces the number of entities with which a given CONTROL AREA must coordinate, and should improve the management of INTERCHANGE TRANSACTIONS and INTERCHANGE SCHEDULES.

The RTO CONTROL AREA participants propose to:

1. Designate their RTO as a ENHANCED SCHEDULING AGENT to act on their behalf with all external ADJACENT CONTROL AREAS with respect to implementation of INTERCHANGE SCHEDULES, including scheduling, confirmation and after-the-fact checkout.

2. Include the Enhanced Scheduling Agent in the Scheduling Path of all Interchange Transactions in the role of Control Area (Intermediary, Source, or Sink as appropriate) with respect to Interchange Transaction management.

3. Include the ENHANCED SCHEDULING AGENT in the reporting of NET SCHEDULED INTERCHANGE in INADVERTENT INTERCHANGE reporting similar to a CONTROL AREA.

By establishing a ENHANCED SCHEDULING AGENT function for the CONTROL AREAS under a multi-party regional agreement or transmission tariff, the following areas can be addressed and/or benefits achieved through the waiver approval:

1. NERC Policy 3B states that INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS. Approval of the waiver will allow CONTROL AREAS bordering a RTO to implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT rather than the RTO participant CONTROL AREAS. For example, a CONTROL AREA interconnected with three CONTROL AREAS within a RTO under the ENHANCED SCHEDULING AGENT, would implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT, rather than the three CONTROL AREAS, significantly reducing its scheduling, coordination and checkout contact requirements.

2. Seams issues associated with multiple CONTROL AREA scheduling paths existing between two adjacent RTOs are minimized by allowing the market to view the seam as a single interface between two RTOs, coordinated by their SCHEDULING AGENTS.

3. Rather than being faced with an ever-increasing number of ADJACENT CONTROL AREAS to implement INTERCHANGE SCHEDULES with and include in INADVERTENT Accounting, any CONTROL AREAS that implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT remain unaffected as the RTO grows in Scope and Scale.

4. The CONTROL AREAS within a RTO served by a ENHANCED SCHEDULING AGENT would be transparent to a transmission customer as the customer reserves transmission service and submits an energy schedule for pass-through transactions across said RTO.

5. By simplifying the transaction implementation process for both participant and non-participant CONTROL AREAS, automation of INTERCHANGE confirmation, scheduling and checkout with the ENHANCED SCHEDULING AGENT becomes achievable.

The proposal simplifies the transaction tagging process for market participants in that there is no longer a need to designate a specific CONTROL AREA contract path within or through the RTO where there may, in fact, be several parallel contract paths possible. The specific scheduling processes implemented between participating CONTROL AREAS within the RTO are internalized and transparent to the market, but will not violate any reliability criteria.

Current Operating Reliability Implications

There are no reliability implications from this waiver.

Policy Conditions for Waiver Recommendation

Policy 3A4

The CONTROL AREA Assesses:

- Transaction start and end time
- Energy profile (ability of generation maneuverability to accommodate)
- Scheduling Path (proper connectivity of ADJACENT CONTROL AREAS)

Conditions: The Control Area Participants will allow the RTO Scheduling Agent to assess proper connectivity on the Scheduling Path.

Policy 3A6

Responsibility for INTERCHANGE TRANSACTION implementation. The SINK CONTROL AREA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy 3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of all CONTROL AREAS on the SCHEDULING PATH in accordance with Policy 3B.

Conditions: The applicants clarify that the Enhanced Scheduling Agent shall assume the role and responsibilities of the INTERMEDIARY, SOURCE, or SINK CONTROL AREA as appropriate with regard to Policy 3, and the individual RTO's Control Areas do not appear in the Scheduling Path on the tag. The RTO's Control Areas will not incorporate these transactions into a schedule in their EMS.

Policy 3B4

INTERCHANGE SCHEDULE confirmation and implementation. The RECEIVING CONTROL AREA is responsible for initiating the CONFIRMATION and IMPLEMENTATION of the INTERCHANGE SCHEDULE with the SENDING CONTROL AREA.

INTERCHANGE SCHEDULE agreement. The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall agree with each other on the:

- Interchange Schedule start and end time
- Ramp start time and rate
- Energy profile

Conditions:

The obligation with respect to confirmation and implementation of INTERCHANGE SCHEDULES under Policy 3B 4 shall be satisfied by the confirmation of all schedules with the Scheduling Agent. The Scheduling Agent shall assume the role and responsibilities that would otherwise be considered that of an INTERMEDIARY, SOURCE, or SINK CONTROL AREA as appropriate with respect to all transactions and schedules involving the RTO or its Control Areas.

Additional Conditions

The Operating Committee approved this waiver on July 16, 2003 with the following condition:

> "With NERC and appropriate regional representation, audit and confirm the Midwest ISO's readiness to perform the functions detailed in the enhanced scheduling agent and energy flow information waivers before they go into effect."

Effective until:

1. **No longer needed, or**
2. **Replaced by NERC Reliability Standard**

Waiver Request – Financial Inadvertent Settlement

Organizations

The Control Area participants of:

- Alliance RTO
- Midwest ISO
- Southwest Power Pool

Operating Policy

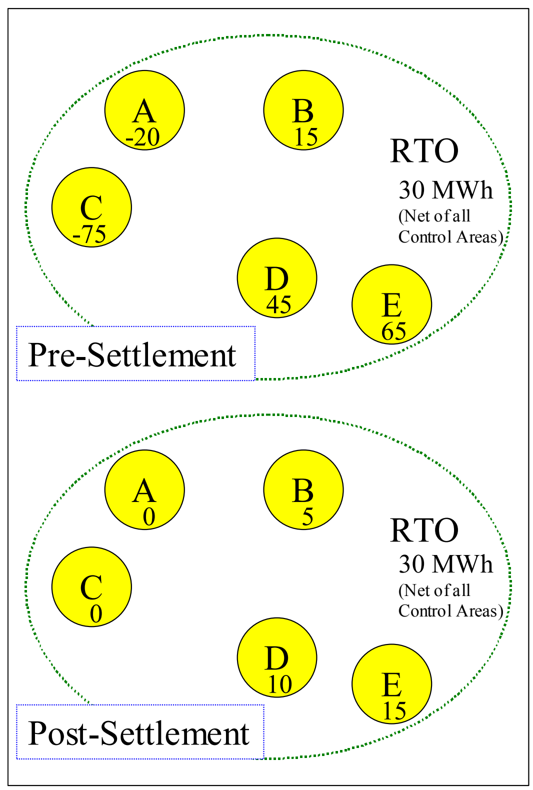
The CONTROL AREA participants of the Alliance RTO, Midwest ISO and Southwest Power Pool are requesting a Waiver of specific provisions of NERC Policy 1, "Generation Control and Performance," to allow financial settlement of INADVERTENT INTERCHANGE within a RTO. The Midwest ISO has filed with the FERC Service Schedule 4 – Energy Imbalance, which contains a provision for financial settlement of INADVERTENT INTERCHANGE between the Midwest ISO CONTROL AREAS.

The RTO Organizations request a waiver from Policy 1, Section F:

5.2. **Other payback methods.** Upon agreement by all REGIONS within an INTERCONNECTION, other methods of INADVERTENT payback may be utilized.

Explanation

The participant CONTROL AREAS ask for a waiver from the requirement that the method of INADVERTENT payback within the RTO be agreed upon by all Regions within the Eastern INTERCONNECTION. Approval of this waiver would allow the participant CONTROL AREAS to adjust their hourly INADVERTENT through an RTO financial settlement process while assuring that the method of INADVERTENT payback will not affect non-participant CONTROL AREAS or the net INADVERTENT owed to the INTERCONNECTION. For reliability reporting, such as for the NERC Area Interchange Error (AIE) report, the participant CONTROL AREAS will continue to report the actual "on-peak" and "off-peak" INADVERTENT INTERCHANGE incurred in all hours. In addition, they will also maintain an adjusted INADVERTENT account to reflect the amount owed to the INTERCONNECTION after financial settlement within the RTO.



Under the financial settlement process, the RTO will determine the amount of INADVERTENT INTERCHANGE that can be financially settled between the CONTROL AREAS within the RTO while assuring that the net INADVERTENT INTERCHANGE for the combined CONTROL AREAS under the RTO will not change.

Approved by Operating Committee
November 21, 2002

The example below and to the right reflects five CONTROL AREAS within a RTO. Before financial settlement of INADVERTENT INTERCHANGE the net of the five CONTROL AREAS' INADVERTENT INTERCHANGE is 30 MWh. As the net INADVERTENT for the hour is positive, all negative INADVERTENT is financially settled within the RTO with 30 MWh remaining to be reported by the CONTROL AREAS post-settlement. Through this process the INADVERTENT INTERCHANGE account with the INTERCONNECTION is unaffected.

Control Area	*Inadvertent*	*Settlement Schedule**	*Adjusted Inadvertent*
A	-20	-20	0
B	15	10	5
C	-75	-75	0
D	45	35	10
E	65	50	15
RTO Net	**30**	**0**	**30**
* MWh settled financially			

Current Operating Reliability

There are no reliability implications from this waiver.

Policy Conditions for Waiver Recommendation

Policy 1F5.2

Other payback methods. Upon agreement by all REGIONS within an INTERCONNECTION, other methods of INADVERTENT payback may be utilized.

Conditions:

The Control Area Participants within the scope of the RTO that financially settle inadvertent will report both the unadjusted and adjusted quantities on the Inadvertent Interchange summary.

Approved by Operating Committee.

March 23–25, 2004

Waiver Request – RTO Inadvertent Interchange Accounting

Organization

The control area participants of the Midwest ISO

Operating Policy

Standards

Policy 1F, Inadvertent Interchange Standard

Requirements

Policy 1G 1.1. – Control Surveys (AIE Survey)

Policy 1G2.2. – **Inadvertent Interchange Summaries (Surveys)**

Explanation

NERC Policy 1.F "Inadvertent Interchange Standard" speaks only of control areas accounting for Inadvertent Interchange. The policy was written before the advent of RTOs.

The CONTROL AREA participants request that the RTO be given an Inadvertent Interchange account. This will support the RTO in meeting its FERC-directed market obligations.

The current model for an LMP market requires financial settlement of all energy receipts and deliveries. This means control areas operating within this market will pay for (or be paid for) their Inadvertent Interchange. Financial settlement of inadvertent is allowed under Policy 1.F. 5.2. (other payback methods) and the *Financial Inadvertent Settlement Waiver*.

The approved *Enhanced Scheduling Agent Waiver* authorizes the RTO to act as a sink or source Control Area in order to manage transactions into, out of, or through the RTO. Approval of this *Inadvertent Interchange Waiver* allows the RTO to manage any financially settled net imbalance with the Interconnection.

Continued Responsibilities

Control areas will continue to perform all the traditional Inadvertent Accounting tasks as outlined in NERC Policy 1.F. and Appendix 1.F. In other words, the RTO control areas will continue to:

- Verify daily Actual Net Interchange with their adjacent control areas and if there are differences, resolve them within the time frame in NERC Policy 1.F.

- Operate to "equal and opposite" Net Actual Interchange with their adjacent control areas.

- Operate to an "equal and opposite" Scheduled Net Interchange with the RTO, consistent with the current *Scheduling Agent Waiver*.

- Verify daily Scheduled Net Interchange with the RTO and if there are differences, resolve them within the time frame in NERC Policy 1.F.

- Report their monthly Inadvertent Interchange data to their respective Regions.

The RTO will also continue to perform all the Inadvertent Accounting tasks as an intermediate control area (as specified in the *Scheduling Agent Waiver*) and source or sink control area (as specified in the *Enhanced Scheduling Agent Waiver*) including:

- Verify daily Scheduled Net Interchange with the RTO control areas and adjacent control areas, and if there are differences, resolve them within the time frame in NERC Policy 1.F.

- Operate to an "equal and opposite" Scheduled Net Interchange with the RTO control areas and adjacent control areas.

- Operate so that the Scheduled Net Interchange of the RTO (Sum of the Scheduled Net Interchanges with the RTO control areas and adjacent control areas) is zero (or equal to the RTO Inadvertent Payback as outlined below).

New Responsibilities

Financially settled Inadvertent would be removed from the control areas' balances. The RTO inadvertent account would reflect the net RTO imbalance with the Interconnection. In order to accomplish this, the RTO would add "equal and opposite" schedules with the RTO control areas after the settlement. The net of these "settlement" schedules will be zero.

As requested by the NERC Resources Subcommittee, the RTO will report its Inadvertent Interchange balance to ECAR. RTO reporting will be consistent with the requirements and timelines for control areas outlined in Policy 1F. In addition, the RTO will maintain records of Inadvertent Interchange financially settled with each control area and will provide AIE data (pre and post settlement) for any surveys or formal data requests.

The RTO will manage and pay back its net Inadvertent Interchange balance following NERC policy. Inadvertent payback will be initiated based on an objective and publicly available process that is triggered on balances exceeding statistical norms (allows normal "breathing" of balances). Inadvertent Payback will be done during periods and in amounts such that payback will not burden others or interfere with time corrections. Financial gain will not factor into the decision to payback or recover Inadvertent Interchange.

Current Operating Reliability

This waiver request is to accommodate after-the-fact transfer of financially settled Inadvertent Interchange. The waiver has no impact on real-time balancing performed by the control areas. The RTO will always operate with a "net zero" Scheduled Interchange. The waiver will not affect the way the RTO control areas perform or calculate CPS and DCS.

The Control Area Participants believe this waiver promotes reliability for two reasons:

- It eliminates the incentive for burdening the Interconnection by manipulating imbalances for financial gain (taking in inadvertent during periods of high price and returning it when prices subside). This is consistent with NERC Operating Committee's charge to the Joint Inadvertent Interchange Task Force (JIITF) and moves the JIITF's recommendations closer to realization.

- Increased transparency as the influence of RTO's markets on the Interconnection will be apparent through this separate RTO Inadvertent Interchange account. Any scheduling or process errors would be traceable through this account.

Effective until:

1. **No longer needed, or**
2. **Replaced by NERC Reliability Standard**

Waiver Request – Scheduling Agent

Organization

The Control Area participants of:

- Alliance RTO
- Midwest ISO
- Southwest Power Pool
- Grid South

Operating Policy

The CONTROL AREA participants request approval of this Waiver to implement a proposed RTO Scheduling Process to meet the RTO obligations under Order 2000, simplify TRANSACTION information requirements for market participants, reduce the number of parties with which CONTROL AREA operators must communicate, and provide a common means to tag TRANSACTIONS within and between RTOs.

The participants are requesting a Waiver of specific provisions of NERC Policy 1, "Generation Control and Performance," and Policy 3, "Interchange," to accommodate a RTO Scheduling Process. The RTO participants propose the following definition of a SCHEDULING AGENT:

SCHEDULING AGENT. A function with the authority to act on behalf of one or more CONTROL AREAS for INTERCHANGE SCHEDULE implementation including creation, confirmation, approval, check-out and associated INADVERTENT INTERCHANGE accounting.

The following specific sections of NERC Policy 1 Version 1a, "Generation Control and Performance," and Policy 3, Version 4, "Interchange," are affected by the RTO Scheduling Process proposed in this Waiver request:

Standards

Policy 1

- Policy 1F, "Inadvertent Interchange Standard"

Requirements

Policy 1

- 1G 1.1 – Control Surveys (AIE Survey)

Policy 3

- 3A 4 – Interchange Transaction Implementation (Assessment)
- 3A 6 – Interchange Transaction Implementation (Implementation)
- 3B 4 – Interchange Schedule Implementation (Confirmation)

Explanation

The SCHEDULING AGENT would be the single point of contact for all external, non-participating CONTROL AREAS or other SCHEDULING AGENTS with respect to scheduling INTERCHANGE into, out of, or through the RTO. Intra-RTO TRANSACTIONS would be handled with the SCHEDULING AGENT acting as the single point of contact between each participating CONTROL AREA similar to an ADJACENT CONTROL AREA. This reduces the number of entities with which a given CONTROL AREA must coordinate, and should improve the management of INTERCHANGE TRANSACTIONS and INTERCHANGE SCHEDULES.

The RTO CONTROL AREA participants propose to:

1. Designate their RTO as a SCHEDULING AGENT to act on their behalf with all ADJACENT CONTROL AREAS with respect to implementation of INTERCHANGE SCHEDULES, including scheduling, confirmation and after-the-fact checkout.

2. Include the SCHEDULING AGENT in the SCHEDULING PATH of all INTERCHANGE TRANSACTIONS effectively placing the RTO SCHEDULING AGENT in the role of an INTERMEDIARY CONTROL AREA with respect to INTERCHANGE TRANSACTION management.

3. Manage any “scheduling error” attributable to the SCHEDULING AGENT and internalize this scheduling error into the INADVERTENT INTERCHANGE accounts of the participating CONTROL AREAS.

4. Include the SCHEDULING AGENT in the reporting of NET SCHEDULED INTERCHANGE in INADVERTENT INTERCHANGE reporting similar to an INTERMEDIARY CONTROL AREA.

By establishing a SCHEDULING AGENT function for the CONTROL AREAS under a multi-party regional agreement or transmission tariff, the following areas can be addressed and/or benefits achieved through the waiver approval:

1. NERC Policy 3B states that INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS. Approval of the waiver will:

    a. Allow the participant RTO CONTROL AREAS to implement INTERCHANGE SCHEDULES directly with the SCHEDULING AGENT, significantly reducing the scheduling, coordination and checkout contacts of the participants.

    b. Allow CONTROL AREAS bordering a RTO to implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT rather than the RTO participant CONTROL AREAS. For example, a CONTROL AREA interconnected with three CONTROL AREAS within a RTO under the SCHEDULING AGENT, would implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT, rather than the three CONTROL AREAS, significantly reducing its scheduling, coordination and checkout contact requirements.

2. Seams issues associated with multiple CONTROL AREA scheduling paths existing between two adjacent RTOs are minimized by allowing the market to view the seam as a single interface between two RTOs, coordinated by their SCHEDULING AGENTS.

3. Rather than being faced with an ever-increasing number of ADJACENT CONTROL AREAS to implement INTERCHANGE SCHEDULES with and include in INADVERTENT Accounting, any CONTROL AREAS that implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT remain unaffected as the RTO grows in Scope and Scale.

4. A RTO participant CONTROL AREA is only involved in the coordination of an INTERCHANGE SCHEDULE if it is the SOURCE or SINK CONTROL AREA in the INTERCHANGE TRANSACTION. For example, the CONTROL AREAS within a RTO would be transparent to the transmission customer as the customer reserves transmission service and submits an energy schedule for pass-through transactions across a RTO.

5. By simplifying the transaction implementation process for both participant and non-participant CONTROL AREAS, automation of INTERCHANGE confirmation, scheduling and checkout with the SCHEDULING AGENT becomes achievable.

The proposal simplifies the transaction tagging process for market participants in that there is no longer a need to designate a specific CONTROL AREA contract path within/through the RTO where there may, in fact, be several parallel contract paths possible. The specific scheduling processes implemented between participating CONTROL AREAS within the RTO are internalized and transparent to the market, but will not violate any reliability criteria.

Current Operating Reliability

There are no reliability implications from this waiver.

Policy Conditions for Waiver Recommendation

Policy 1F4.1

INADVERTENT INTERCHANGE Accounting. Adjacent CONTROL AREAS shall operate to a common NET INTERCHANGE SCHEDULE and ACTUAL NET INTERCHANGE value and shall record these hourly quantities, with like values but opposite sign. Each CONTROL AREA shall compute its INADVERTENT INTERCHANGE based on the following:

> **Daily accounting**. Each CONTROL AREA, by the end of the next business day, shall agree with its adjacent CONTROL AREAS to the hourly integrated values of:
>
> - NET INTERCHANGE SCHEDULE
> - NET ACTUAL INTERCHANGE

Conditions: The Control Area Participants shall designate their Scheduling Agent to be responsible for agreeing to NET INTERCHANGE SCHEDULE values with Adjacent Control Areas or other Scheduling Agents. The Control Areas will continue to calculate INADVERTENT INTERCHANGE based on Interchange Transactions sourcing and sinking in those Control Area.

Policy 1F4.2

Monthly accounting. Each CONTROL AREA shall use the agreed-to Daily accounting data to compile the monthly accumulated INADVERTENT INTERCHANGE for the On-Peak and Off-Peak hours of the month. **[Refer to "Inadvertent Interchange Accounting Training Document"]**

Conditions: The Control Area Participants shall use, on a monthly basis, the NET INTERCHANGE SCHEDULES with their RTO Scheduling Agent in compiling Inadvertent Interchange reports. The RTO Scheduling Agent shall use all NET INTERCHANGE SCHEDULES with adjacent Control Areas or other Scheduling Agents.

Policy 1F6

INADVERTENT INTERCHANGE summary. Each CONTROL AREA shall submit a monthly summary of INADVERTENT INTERCHANGE as detailed in Appendix 1F, "INADVERTENT INTERCHANGE Energy Accounting Practices and Dispute Resolution Process." These summaries shall not include any after-the-fact changes that were not agreed to by the SOURCE CONTROL AREA, SINK CONTROL AREA and all INTERMEDIARY CONTROL AREA(s).

Conditions: The Control Area Participants shall continue to report NET ACTUAL INTERCHANGES with their physically interconnected Control Areas, but will report NET INTERCHANGE SCHEDULES only with their RTO Scheduling Agent. The RTO Scheduling Agent will report all NET INTERCHANGE SCHEDULES with adjacent Control Areas or other Scheduling Agents.

Policy 1G

Surveys. The CONTROL AREAS in each INTERCONNECTION shall perform each of the following surveys, as described in the Performance Standard Training Document, when called for by the Performance Subcommittee:

> **AIE survey.** Area Interchange Error survey to determine the CONTROL Areas' INTERCHANGE error(s) due to equipment failures or improper SCHEDULING operations, or improper AGC performance.

Conditions: The Control Area Participants will allow the RTO Scheduling Agent to submit the AIE survey for Control Areas within the RTO's boundary in a form similar to that proposed under Policy 1F.

Policy 3A4

The CONTROL AREA Assesses:

- Transaction start and end time
- Energy profile (ability of generation maneuverability to accommodate)
- Scheduling Path (proper connectivity of ADJACENT CONTROL AREAS)

Conditions: The Control Area Participants will allow the RTO Scheduling Agent to assess proper connectivity on the Scheduling Path.

Policy 3A6

Responsibility for INTERCHANGE TRANSACTION implementation. The SINK CONTROL AREA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy 3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of all CONTROL AREAS on the SCHEDULING PATH in accordance with Policy 3B.

Conditions: The applicants clarify that for pass-through transactions, the RTO Scheduling Agent shall assume the role and responsibilities of the INTERMEDIARY CONTROL AREA, and the individual RTO's Control Areas do not appear in the Scheduling Path on the tag. The RTO's Control Areas will not incorporate these transactions into a schedule in their EMS.

Policy 3B4

INTERCHANGE SCHEDULE confirmation and implementation. The RECEIVING CONTROL AREA is responsible for initiating the CONFIRMATION and IMPLEMENTATION of the INTERCHANGE SCHEDULE with the SENDING CONTROL AREA.

INTERCHANGE SCHEDULE agreement. The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall agree with each other on the:

- Interchange Schedule start and end time
- Ramp start time and rate
- Energy profile

Conditions:

The obligation with respect to confirmation and implementation of INTERCHANGE SCHEDULES under Policy 3B 4 shall be satisfied by the confirmation of all schedules with the Scheduling Agent. The Scheduling Agent shall assume the role and responsibilities that would otherwise be considered that of an INTERMEDIARY CONTROL AREA with respect to all transactions and schedules involving the RTO or its Control Areas.

Effective until replaced by the applicable Reliability Standard.

Waiver Request – Tagging Dynamic Schedules and Inadvertent Payback

Entity
Western Electricity Coordinating Council – Operating Committee

Policy
Policy 3 “Interchange”

Waiver Requested
Add the following to third bullet under Policy 3 Section A.2.1 – Deference to the WECC where Dynamic Interchange Schedules are of known amounts by the sending and receiving control areas, have existing transmission capacity, and the Transmission Providers are aware of the amounts which are exempt from being tagged.

Add the following to the fourth bullet under Policy 3 Section A.2.1 – Deference to the WECC where existing procedure require notification of bilateral payback to be made via the WECC Messaging network where all parties are notified. Amounts less than or equal to 25 megawatts per hour are not required to be tagged.

Explanation
The WECC Operating Committee and Interchange Scheduling and Accounting Subcommittee requested a waiver to Policy 3 to tagging requirements for bilateral inadvertent interchange payback schedules and dynamic schedules.
The tagging requirements simply do not apply to operations in the Western Interconnection. Adding a tagging requirement for dynamic schedules will add a burden on scheduling entities and will not provide a substantial benefit. CA and TP have real-time scheduling information on dynamic schedules.

Unilateral inadvertent payback is not allowed in the WECC.

Exhibit B — Representative Sample of Experts on Drafting Teams

VERSION 0 STANDARD DRAFTING TEAM		
NAME	TITLE	ORGANIZATION
Robert W. Millard	Chairman	MAIN
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J. Roman Carter	Project Manager Generating Fleet Operations	Southern Company Generation and Energy Marketing
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E. Nick Henery	Energy Coordinator, Special Projects	Sacramento Municipal Utility District
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Colin Loxley	Manager – Process, Standards, and Development	Public Service Electric and Gas Company

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Brian F. Thumm	Supervisor – Transmission Planning	Entergy Services, Inc.
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Gerry Cauley	Staff Coordinator	NERC

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Franklin Bristol	Manager, Operations Engineering	American Transmission Company, LLC
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James Detweiler		FirstEnergy Corp.
Roger Green	E&I Manager	Southern Company Services
Donal Kidney	Senior Engineer	Northeast Power Coordinating Council
E. Nick Henery	Energy Coordinator, Special Projects	SMUD
Sharma Kolluir		Entergy
Mark Kuras	Senior Engineer, Interregional Coordination and Compliance	PJM
Chuck Lawrence		American Transmission Company, LLC
Henry Miller	Principal Electrical Engineer	American Electric Power
Mahendra Patel	Manager, Generation Analysis	PJM Interconnection
John Ratajczyk		American Transmission Company, LLC

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Larry Smith	Vice President — Commercial Operations	Alabama Power Co.
Bob Stuart	Director of Business Development, Principal T&D Consultant	Elequant
Lee Taylor	Chief Engineer	Southern Company Services, Inc.
Martin Trence		Xcel Energy Services
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Weston Davis		Central Maine Power an Energy East Company
Randall Ford Gann		Alabama Power Company Operating Co. of the Southern Company
Ralph L. Hale		Entergy Transmission
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Mark Heffley		Georgia Transmission Corporation
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Michael D. Johnson		Bonneville Power Administration
George Juhn		Hydro One Networks, Inc.
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Randall H. Miller		PacifiCorp System Forester

David S. Morrell		New York State Dept. of Public Service
Michael Neal		APS
Robert Novembri		CN Utility Consulting
B. Don Russell		Texas A&M University Department of Electrical Engineering
John E. Schechter		American Electric Power
Gwen Shrimpton		BC Transmission Corporation
Raffy Stepanian		California Public Utilities Commission
Thomas E. Sullivan		National Grid USA
John Tamsberg		Florida Power and Light Company Transmission Operations
Richard Wolowicz		Public Service Electric and Gas Company
Jeffery M. Wright		Vermont Electric Power Company, Inc.
Bruce Poole	FERC Observer	Federal Energy Regulatory Commission
Tim Ponseti	TVA General Manager Observer	TVA
John Twitchell	Staff Coordinator	NERC

DETERMINE FACILITY RATINGS, OPERATING LIMITS, AND TRANSFER CAPABILITIES DRAFTING TEAM		
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Exhibit C — Reliability Standards Process Manual, Version 4

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

NERC Reliability Standards Process Manual

Version 4.0 — Adopted by the NERC Board of Trustees

August 2, 2005

A New Jersey Nonprofit Corporation
Phone 609-452-8060 ■ Fax 609-452-9550 ■ URL www.nerc.com

Table of Contents

Introduction

Purpose

This manual defines the characteristics of a reliability standard of the North American Electric Reliability Council (NERC) and establishes the process for development of consensus for approval, revision, reaffirmation, and withdrawal of such standards. NERC reliability standards apply to the reliability planning and reliable operation of the bulk electric systems of North America.

Authority

This manual is published by the authority of the NERC Board of Trustees, who shall have the sole authority to modify the manual. The manual may, at the discretion of the Board of Trustees, be filed with regulatory agencies, consistent with the NERC Certificate of Incorporation and Bylaws. A procedure for revising the manual is provided in the section titled Maintenance of Reliability Standards and Process.

Background

NERC is a nonprofit corporation formed as a result of the Northeast blackout in 1965 to promote the reliability of the bulk electric systems of North America. NERC comprises ten regional reliability organizations that account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

NERC works with all stakeholder segments of the electric industry, including electricity users, to develop standards for the reliable planning and operation of bulk electric systems. Historically, NERC standards were effectively applied on a voluntary basis. The NERC Board of Trustees has established that enforcement of these standards is a necessary step for the continuing reliability of the North American bulk electric systems.

While NERC reliability standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. Reliability is a necessity for electricity markets, and robust electricity markets can support reliability.

This manual has been developed for implementation while NERC is in a transition state to become the North American Electric Reliability Organization (NAERO). Once reliability legislation is enacted, and as NAERO is formed, this manual may be revised as necessary to incorporate any additional regulatory requirements associated with the development, approval, and implementation of reliability standards.

Principles

Need for Guiding Principles

The NERC Board of Trustees has adopted reliability principles and market interface principles to define the purpose, scope, and nature of reliability standards. As these principles are fundamental to reliability and the market interface, these principles provide a constant beacon to guide the development of reliability standards. The Board of Trustees may modify these principles from time to time, as necessary, to adapt its vision for reliability standards.

Persons and committees that are responsible for the reliability standards process shall consider these principles in the execution of those duties.

Reliability Principles

NERC reliability standards are based on certain reliability principles that define the foundation of reliability for North American bulk electric systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk electric systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Market Interface Principles

Recognizing that bulk electric system reliability and electricity markets are inseparable and mutually interdependent, all reliability standards shall be consistent with the market interface principles. Consideration of the market interface principles is intended to ensure that reliability standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

Reliability Standard Definition, Characteristics, and Elements

Definition of a Reliability Standard

A reliability standard defines certain obligations or requirements of entities that operate, plan, and use the bulk electric systems of North America. The obligations or requirements must be material to reliability and measurable. Each obligation and requirement shall support one or more of the stated reliability principles and shall be consistent with all of the stated reliability and market interface principles.

Characteristics of a Reliability Standard

Reliability standards include standards for the operation and planning of interconnected systems, consistent with the reliability and market interface principles. The format and process defined by this manual applies to all reliability standards.

A reliability standard shall have the following characteristics:

- **Material to reliability** — A reliability standard shall be material to the reliability of the bulk electric systems of North America. If the reliability of the bulk electric systems could be compromised without a particular standard or by a failure to comply with that standard, then the standard is material to reliability.
- **Measurable** — A reliability standard shall establish technical or performance requirements that can be practically measured.

Although reliability standards have a common format and process, several types of reliability standards may exist, each with a different approach to measurement:

- **Technical standards** related to the provision, maintenance, operation, or state of electric systems will likely contain measures of physical parameters and will often be technical in nature.
- **Performance standards** related to the actions of entities providing for or impacting the reliability of bulk electric systems will likely contain measures of the results of such actions, or the nature of the performance of such actions.
- **Preparedness standards** related to the actions of entities to be prepared for conditions that are unlikely to occur but are critical to reliability will likely contain measures of such preparations or the state of preparedness, but measurement of actual outcomes may occur infrequently or never.
- **Organization certification standards** define the essential capabilities to perform reliability functions. Such standards are used to credential organizations that have the requisite capabilities.

Elements of a Reliability Standard

A reliability standard shall consist of the elements shown in the reliability standard template. These elements are intended to apply a systematic discipline in the development and revision of 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 compliance elements associated with each standard.

All mandatory requirements of a 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 the manual.

Performance Elements of a Reliability Standard

Identification Number	A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the standards.
Title	A brief, descriptive phrase identifying the topic of the standard.
Effective Date and Status	The effective date of the standard or, prior to adoption of the standard by the Board of Trustees, the proposed effective date. 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 standard. The purpose shall explicitly state what outcome will be achieved by the adoption of the standard. The purpose is agreed to early in the process as a step toward obtaining approval to proceed with the development of the standard. The purpose should link the standard to the relevant principle(s).
Requirement(s)	Explicitly stated technical, performance, and preparedness 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. 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.)
Measure(s)	Each requirement shall be addressed by one or more measures. Measures are used to assess performance and outcomes for the purpose of determining compliance with the requirements stated above. Each measure will identify to whom the measure applies and the expected level of performance or outcomes required to demonstrate 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 measure 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 and each requirement shall clearly indicate which measure(s) apply to that requirement.

Glossary of Terms Used in Standards

Definitions of Terms	All defined terms used in reliability standards shall be defined in the glossary. Definitions may be approved as part of a standard action or as a separate action. All definitions must be approved in accordance with the standards process.

Compliance Elements[1] of a Standard

Compliance Monitoring Process	Defines for each measure: • The specific data or information that is required to measure performance or outcomes. • The entity that is responsible to provide 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 data or information to assess performance or outcomes. • 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.
Levels of Non-Compliance	Defines the levels of non-compliance for each measure, typically based on the actual or potential severity of the consequences of non-compliance.

Supporting Information Elements

Interpretations	Formal interpretations of the reliability standard. Interpretations are temporary, as the standard should be revised to incorporate the interpretation. Interpretations are developed through a process described in the section Interpretations of Standards.
Supporting References	This section will reference related documents that support implementation of the reliability standard, but are not themselves mandatory. Examples include, but are not limited to: • Developmental history of the standard and prior versions. • Subcommittee(s) responsible for standard. • Notes pertaining to implementation or compliance. • Standard references. • Standard supplements. • Procedures. • Practices.

[1] While the compliance elements are developed and approved in the NERC process along with the core elements of a standard, the compliance elements will not be included in any standard submitted to ANSI for approval as an American National Standard.

	• Training references. • Technical references. • White papers. • Internet links to related information.

Roles in the Reliability Standards Development Process

Nomination, Revision, or Withdrawal of a Standard

Any member of NERC, including any member of a regional reliability organization, or group within NERC shall be allowed to request that a 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 North American bulk electric systems shall be allowed to request a reliability standard be developed, modified, or withdrawn.

Process Roles

Board of Trustees — The NERC Board of Trustees shall consider for adoption as reliability standards the standards that have been approved by a ballot pool. Once the board adopts a reliability standard, compliance with the standard will be enforced consistent with the effective date.

Stakeholders Committee — The NERC Stakeholders Committee shall advise the Board of Trustees on reliability standards presented for adoption by the board.

Standards Authorization Committee (SAC) — The SAC shall consist of two members of each of the stakeholder segments in the Registered Ballot Body. The SAC shall meet at regularly scheduled intervals (either in person, or by other means) to consider which requests for new or revised standards should be assigned for development. The SAC will manage the standards development process. The responsibilities of the SAC 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 manual; and advising the Board of Trustees on standard development matters. Under no circumstance will the SAC change the substance of a draft standard. The standards process manager serves as secretary to the SAC.

Registered Ballot Body — The Registered Ballot Body comprises all entities that:

1. Qualify for one of the stakeholder segments approved by the Board of Trustees[2], and
2. Are registered with NERC as potential ballot participants in the voting on standards, and
3. Are current with any designated fees.

Each member of the Registered Ballot Body is eligible to participate in the voting process (and ballot pool) for each standard action.

Ballot Pool — Each standard action has its own ballot pool formed of interested members of the Registered Ballot Body. The ballot pool comprises those members of the Registered Ballot Body that respond to a pre-ballot survey for that particular standard action.

[2] Appendix B contains a description of the latest version of the stakeholder segments approved by the Board of Trustees.

The ballot pool will ensure, through its vote, the need for and technical merits of a proposed standard action and the appropriate consideration of views and objections received during the development process. The ballot pool votes to approve each standards action.

Standards Process Manager — The reliability standards process shall be administered by a standards process manager. The standards process manager is responsible for ensuring that the development and revision of standards is in accordance with this manual. The standards process manager works to ensure the integrity of the process and consistency of quality and completeness of the reliability standards. The standards process manager facilitates all steps in the process.

Standards Process Staff — NERC staff will assist the SAR drafting teams and standard drafting teams.

Subcommittees, Working Groups, and Task Forces — The subcommittees, working groups, and task forces within NERC serve an active role in the standards process:

- Initiate standards actions by developing SARs.
- Post comments (views and objections) to standards actions.
- Participate on standard drafting teams.
- Assist in the implementation of approved standards.
- Serve as industry spokespersons by encouraging others within their NERC region and stakeholder segment to participate in the standards development process.
- Serve as industry monitors to assess the impact of a standard's implementation.
- Provide technical oversight in response to changing industry conditions.
- Identify the need for new standards.

NERC and Regional Reliability Organization Members — The members of NERC and the regional reliability organizations may initiate new or revised standards and may comment on proposed standards.

Requester — A requester is any person (organization, company, government agency, individual, etc.) that submits a complete request for development, revision, or withdrawal of a standard. Any person 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 requestor is assisted by the SAR drafting team (if one is appointed by the SAC) to respond to comments and to decide if and when the SAR is forwarded to the SAC with a request to draft a standard. The requestor is responsible for the SAR, assisted by the SAR drafting team, until such time the SAC authorizes development of the standard. The requester has the option at any time to allow the SAR drafting team to assume full responsibility for the SAR. The requester may chose to participate in subsequent standard drafting efforts related to the SAR.

Compliance Enforcement Program — The mission of the NERC compliance enforcement program is to manage and enforce compliance with NERC reliability standards. The development of a reliability standard, in particular the measures and compliance elements of the standard, shall have direct input from the compliance enforcement program. Field testing will also be coordinated with the compliance program. The compliance program director and appropriate working groups shall provide inputs and comments during the standards development process to ensure the measures will be effective and other aspects of the compliance enforcement program can be practically implemented.

SAR Drafting Team — A team of technical experts assigned to a SAR, that:

- Assists in refining the SAR,
- Considers and responds to comments, and
- Participates in industry forums to help build consensus on the SAR.

Standard Drafting Team — A team of technical experts, approved by the SAC, that:

- Develops the details of the standard,
- Considers and responds to comments, and
- Participates in industry forums to help build consensus on posted draft standards.

Joint Interface Committee (JIC) — The JIC's purpose is to ensure that the development of wholesale electric business practices and reliability standards is harmonized and that every effort is made to minimize duplication of effort between NERC and the North American Energy Standards Board (NAESB). The JIC is staffed by representatives of NERC, NAESB, and the ISO/RTO Council and is governed by the provisions of a Memorandum of Understanding executed by the three entities. The JIC will review all standards development proposals received by NERC and NAESB to determine whether NERC or NAESB should develop a particular standard. The JIC will also coordinate the annual work plans of the three organizations.

Reliability Standards Consensus Development Process

Overview

The process for developing and approving reliability standards is generally based on the procedures of the American National Standards Institute (ANSI) and other standards-setting organizations in the United States and Canada. The NERC process has the following characteristics:

- **Due process** — Any person with a direct and material interest has a right to participate by: a) expressing an opinion and its basis, b) having that position considered, and c) appealing if adversely affected.
- **Openness** — Participation is open to all persons who are directly and materially affected by North American bulk electric system reliability. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements. All meetings of the SAC and drafting teams shall be open and publicly noticed on the NERC web site.
- **Balance** — The NERC standards development process shall have a balance of interests and shall not be dominated by any single interest category.

The NERC process is intended to develop consensus, on both the need for the standard, and the proposed 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).
- **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. Once the need for the standard has been established by a SAR, comments should focus on aspects of the draft standard itself.
- **Field-testing of the draft standard** and measures. The SAC shall determine the need and extent of field-testing, considering the recommendations of the NERC compliance program director and the standard drafting team. Field-testing may be industry-wide or may consist of one or more lesser-scale demonstrations. Field-testing should be cost effective and practical, yet sufficient to ensure clarity of the standard and to validate the requirements, measures, measurement processes, and other elements of the standard necessary to implement the compliance program. 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 ballot pool, using the NERC Weighted Segment Voting Model.
- **Re-ballot to consider specific comments** by those submitting comments with negative votes.
- **Adoption by the Board of Trustees**.
- **An appeals mechanism** as appropriate for the impartial handling of substantive and procedural complaints regarding action or inaction related to the standards process.

The first three steps in the process serve to establish consensus on the need for the standard.

Step 1 — Request a Standard or Revision to an Existing Standard

Objective: *A valid SAR that clearly justifies the purpose and describes the scope of the proposed standard action and conforms to the requirements of a SAR outlined in Appendix A.*

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 action (Step 5), which the SAC 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 SAR first to get agreement on the scope and purpose, and the standard later in Step 6.*

Requests to develop, revise, or withdraw[3] a reliability standard shall be submitted to the standards process manager by completing a SAR. The SAR is a description of the new or revised standard. The SAR provides sufficiently descriptive detail to clearly define the scope of the standard. The SAR also states the purpose of the standard. A needs statement will provide the detailed 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 A provides a sample of the information in a SAR. The standards process manager shall maintain this 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 will submit the SAR to the standards process manager electronically and the standards process manager will electronically acknowledge receipt of the SAR. The standards process manager will assist the submitting party in developing the SAR and verify that the SAR conforms to this manual.

The standards process manager shall forward all properly completed SARs to the SAC. The SAC shall meet at established intervals to review all pending SARs. The frequency of this review process will depend on workload, but in no case shall a properly completed SAR wait for SAC action more than 30 days from the date of receipt. This review will determine if the SAR is sufficiently stated to guide standard development and whether the SAR is consistent with requirements in the manual. The SAC, guided by the reliability and market interface principles, may take one of the following actions:

[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.

- Remand the SAR back to the standards process manager for additional work. In this case, the standards process manager may request additional information for the SAR from the requester and will advise the requester of the SAC's reasons for remanding the SAR within 10 days of the action.
- Accept the SAR as a candidate for a new or revised standard, and authorize posting of the SAR for stakeholder comment.
- Reject the SAR. If the SAC rejects a SAR, it will provide a written explanation for rejection to the requester within 10 days of the rejection decision.

If the SAC accepts a SAR as a candidate for a new or revised standard, it may at its discretion appoint a SAR drafting team. The SAR drafting team would be tasked with assisting the requester in further developing the SAR and considering stakeholder comments on that SAR. The SAC may also choose to allow the requester to perform these tasks.

If the SAC remands or rejects a SAR, the requester may file an appeal following the appeals process provided in this manual.

The status of SARs shall be tracked electronically. 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 requestor's proposed standard action.*

Sequence Considerations: *A SAR may be posted only after completion of Step 1. A SAR may, at the discretion of the SAC, be posted for comment concurrently with a draft standard (Step 6). In this case the draft standard would have a conditional status until the JIC assigns development of the standard to NERC.*

Once a SAR has been accepted by the SAC as a candidate for the development of a new or revised standard, the SAR will be posted for the purpose of soliciting public comments, as soon as practical as determined by the SAC. SARs will be posted and publicly noticed at regularly scheduled intervals. Establishment of a regular time for posting of SARs will allow interested parties to know when to expect the next set of SARs.

Comments on the SARs will be accepted for at least a 30-day period from the notice of posting. Comments will be accepted online using an internet-based application. The standards process manager will provide a copy of the comments to the requester and the SAR drafting team, if one has been appointed. Based on the comments, the requester may decide to submit the SAR for authorization to develop the standard, to withdraw the SAR, or to revise and resubmit it to the standards process manager for another posting, as soon as practical as determined by the SAC. If appointed, the SAR drafting team shall assist the requester in the reviewing comments, determining whether to continue or not, and making any necessary revisions for another posting.

The SAC is responsible for the work flow of standards development. Based on the SAR priority, comments received, and an evaluation of available resources, the SAC will determine the appropriate timing of postings after the initial SAR posting and comment period.

The requester, assisted by the SAR drafting team if one is appointed, 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. In addition, each objector shall be informed that an appeals procedure exists within the NERC standards process.

While there is no established limit on the number of times a SAR may be posted for comment, the SAC retains the right to reverse its prior decision and reject a SAR if it believes continued revisions are not productive. Once again, the SAC shall notify the requester in writing of the rejection following the appeals procedure.

During the SAR comment process, the requester may become aware of potential regional differences related to the proposed standard. To the extent possible, any regional differences or exceptions should be made 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.

The requester, up to this point in the development process, may elect to withdraw the request at any time. Once the SAC authorizes development of a standard based on the SAR (Step 3) the requester may no longer withdraw the SAR, as it becomes the responsibility of the drafting team working on behalf of all stakeholders.

Step 3 — Authorization to Proceed With Drafting a New or Revised Standard

Objective: *Authorize development of a standard that is consistent with a SAR and for which there is stakeholder consensus on the need, scope and applicability.*

Sequence Considerations: *The SAC may formally authorize the development of a standard 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 SAC from authorizing a concurrent posting of the draft standard for comment along with the SAR. If a draft standard is posted for comment concurrently with the SAR, it is with the understanding that further development of the draft standard is conditioned on achieving stakeholder consensus through comments on the associated SAR and assignment of the standard by the JIC to NERC for development.*

After receiving public comments on the SAR, the requester may decide to submit the SAR to the SAC for authorization to draft the standard. The SAC reviews the comments received in response to the SAR and any revisions to the SAR.

Prior to authorizing a standard for development, the SAC will coordinate the proposed standard request with the JIC and request that the JIC assign the standard to NERC for development. The SAC may submit the SAR to the JIC for consideration at any time during Steps 1 or 2.

The SAC, once again considering the reliability and market interface principles and considering the public comments received and their resolution, may then take one of the following actions:

- Authorize drafting the proposed standard or revisions to a standard.
- Reject the SAR with a written explanation to the requester and post that explanation.

If the SAC rejects a SAR, the requester may file an appeal.

Once the SAC authorizes development of the standard, the SAC shall assign responsibility for the development of the standard to one or more drafting teams as appropriate. At that time, the requester no longer has responsibility for managing the standard request.

Step 4 — Appoint Standard Drafting Team

Objective: *Appoint a standard drafting team that has the expertise, competencies, and diversity of views that are necessary to develop the standard.*

Sequence Considerations: *The SAC may appoint a standard drafting team concurrently with or after authorization of the development of a standard (Step 3).*

Once a SAR has been authorized for development of a standard by the SAC, the SAC shall determine the method for populating a standard drafting team. Typically, the SAC would direct the conduct of a public nominations process to populate the standard drafting team. In some cases, the SAC may appoint the members of the SAR drafting team or the requester to act as the standard drafting team. If this method of populating a drafting team is used, the SAC shall still solicit additional members through a public solicitation of nominees and appoint additional members as needed.

The standards process manager shall post a request that interested parties complete a standard drafting team nomination form. Those individuals who complete and submit these self-nomination forms shall be considered for appointment to the associated standard drafting team. The standards process manager shall recommend a list of candidates for appointment to the team and shall submit the list to the SAC. The SAC may accept the recommendations of the standards process manager or may select other individuals to serve on the standard drafting team. This team shall consist of a group of people who collectively have the necessary technical expertise and work process skills. The SAC shall appoint the standard drafting team, including its officers. The standards process manager shall assign staff personnel as needed to assist in the drafting of the standard.

The SAC may, in lieu of an open nomination, use the SAR drafting team (if one was appointed) or the requester as the standard drafting team. The SAC should consider this option only if the necessary expertise, competencies, and diversity of views (to respond fairly to comments) is addressed. If the SAR drafting team or requester is not utilized as the standard drafting team, individuals associated with either may be nominated through the open process to join the standard drafting team.

Once it is appointed by the SAC, the standard drafting team is responsible for making recommendations to the SAC regarding the remaining steps in the standards process. The requestor may continue to assist the drafting team and participate in the standards process.

The SAC may decide that more than one drafting team is required for a standard action and divide the SAR into multiple efforts. The SAC may also supplement the membership of a standard drafting team at any time to ensure the necessary competencies and diversity of views are maintained throughout the standard development effort.

Step 5 — Draft New or Revised Standard

Objective: *Develop a standard within the scope of the SAR.*

Sequence Considerations: *Generally development of the draft standard follows the authorization by the SAC (Step 3) and appointment of a standard drafting team (Step 4). Steps 5 and 6 may be iterated as necessary to consider stakeholder comments and build consensus on the draft standard.*

The appointed standard drafting team will develop a draft of the standard. In addition to drafting the text of the standard, development may include research, analysis, information gathering, testing, and other activities. The drafting of measures and compliance elements of the standard will be coordinated with the compliance program.

The drafting team may use a draft standard submitted by the requester as its initial draft, if one was submitted by the requester concurrently with the SAR.

Once the standard has been drafted, the standards process manager will review the standard for consistency of quality and completeness. The standards process manager will also ensure the draft standard is within the scope and purpose identified in the SAR. This review should occur within a 30-day period of the submittal of the draft standard. Once the standards process manager has completed this review, the new or revised standard will be submitted to the SAC to request posting for public comment.

The SAC should authorize posting of draft standards in a timely manner, but may consider priorities among various standards actions and the ability of stakeholders to review multiple actions at the same time. SAC will approve the posting and set the posting start and end dates.

If the standard drafting team determines that the scope of the SAR is inappropriate based on its own work and stakeholder comments, the team shall notify the SAC. The drafting team 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 drafting team 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 drafting team shall provide detailed justification of need for reducing the scope. The SAC, based on the drafting team recommendation and a review of stakeholder comments, will determine if the change in scope is acceptable.

If the standard drafting team 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 drafting team may initiate or recommend another requestor initiate a new SAR (Step 1) to develop the expanded or modified scope. At no time will a drafting team develop a standard that is not within the scope of the SAR that was authorized for development.

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 improve consensus.*

Sequence Considerations: *The posting of a draft standard will typically occur after the appointment of a standard drafting team and development of a draft by the team. Alternatively, a draft standard submitted by the requestor may be posted for comment concurrently with the associated SAR, with the condition that the SAR and draft standard meet the requirements of this manual and are consistent with each other. In all cases, public comments on the draft standard must be solicited prior to SAC approving the standard going to ballot (Step 9).*

Once the SAC approves the posting of a draft standard and sets the posting start and end dates, the standards process manager will post the draft standard in the next regular posting interval for the purpose of soliciting public comments. The posting of the draft standard will be linked to the SAR for reference. Comments on the draft standard will be accepted for at least one 45-day period from the notice of posting.

Additional posting periods may be set by the SAC and shall be at least 30 days. Comments will be accepted online using an internet-based application along with other electronic means as necessary.

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 standard and reasons for that recommendation.

The drafting team shall develop an implementation plan for the standard to be posted 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.

Step 7 — Field Testing

Objective: *Determine what 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 standard drafting team may recommend to the SAC that a test of one or more aspects of a standard is needed. The NERC compliance program director will also evaluate whether field-testing of the compliance elements of the proposed new or revised standard is needed and advise the SAC. The SAC will approve all field tests of proposed standards based on the recommendations of the standard drafting team and the compliance program director. If needed, the SAC will also request inputs on technical matters from applicable standing committees or other experts.

Once the field testing plan is approved, the standards process manager will, under the direction of the SAC, oversee the field-testing of the standard.

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 may be sufficient. Comments may be solicited during the field test period.

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 standards process manager will assemble the comments on the draft standard and distribute those comments to the standard drafting team and the requester. The standard drafting team, 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, in addition to public posting of the responses. In addition, each objector shall be informed that an appeals process exists within the NERC standards process.

Based on comments received, the drafting team may determine there is an opportunity to improve consensus for the standard. In this case, the standard drafting team 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 drafting team should ensure the potential benefits of another posting outweigh the burden on the drafting team and stakeholders. Returning to Step 5 to continue working on the standard is the prerogative of the drafting team, subject to SAC oversight.

If the standard drafting team determines the draft standard is ready for ballot, the drafting team shall submit the draft standard to the SAC 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 standard drafting team 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 effect or use of the standard. Any non-substantive changes made prior to going to ballot shall be identified to stakeholders at the time of the ballot notice.

When the SAC receives a draft standard that is recommended for ballot, the SAC 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 SAC shall remand the proposed standard to the standard drafting team to address the deficiencies. If the proposed standard passes the review, the SAC shall set the proposed standard for ballot as soon as the work flow will accommodate.

If the drafting team determines there is insufficient consensus to ballot the standard and that further work is unlikely to achieve consensus, the drafting team may recommend to the SAC that the standard drafting be terminated and the SAR withdrawn. The SAC will consider the recommendation of the drafting team and stakeholder comments and may terminate the standard drafting and accept the withdrawal of the SAR. If the SAC believes the recommendation is unsubstantiated, the SAC may direct other actions consistent with this manual, such as requesting the drafting team to continue or appointing a new drafting team.

Step 9 — Ballot the New or Revised Standard

Objective: *Approve the proposed standard by vote of industry stakeholders.*

Sequence Considerations: *The SAC shall determine that all requirements of Steps 1 through 8 have been satisfactorily met before authorizing an action to go to ballot.*

Ballot Pool

The Standards Process Manager shall establish a ballot pool for a standard action at least 30 days prior to the start of a ballot and no later than the final posting of a draft standard for comment. The standards process manager shall send a notice to every entity in the Registered Ballot Body. The purpose of this notice is to establish a ballot pool to participate in the consensus development process and ballot the proposed standards action. The ballot pool may be established early in the standards development process to encourage active participation in the development process.

Any member of the Registered Ballot Body may join or drop out of a ballot pool until the ballot period begins (Step 9). No Registered Ballot Body member may join or leave the ballot pool once the first ballot starts, including between the first ballot and a recirculation ballot. The standards process manager shall coordinate changes to the membership of the ballot pool and publicly post the standard ballot pool for each standard action.

First Ballot

If a decision is made to submit the draft standard to a vote, the draft standard, all comments received, and the responses to those comments shall be posted electronically to the ballot pool and noticed at least 30 days prior to the start of the ballot.

The ballot will be conducted electronically. Each standard has its own ballot pool and all members of the ballot pool shall be eligible to vote on the associated standard. The time window for voting will be designated when the draft standard is posted to the ballot pool. In no case will the voting time window start sooner than 30 days from the notice of the posting to the ballot pool. Typically, the voting time window will be a period of ten days. This provides a total of 40 days from the initial notice until the end of the voting period.

Approval of a reliability standard or revision to a reliability standard requires both:

- A quorum, which is established by at least 75% of the members of the ballot pool submitting a response with an affirmative vote, a negative vote, or an abstention[4]; and
- A two-thirds majority of the weighted segment votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions, and non-responses.

The following process is used to determine if there are sufficient affirmative votes. (See Appendix C, "Examples of Weighted Segment Voting Calculation."):

- The number of affirmative votes cast in each segment will be divided by the sum of affirmative and negative votes cast to determine the fractional affirmative vote for each segment. Abstentions and non-responses will not be counted for the purposes of determining the fractional affirmative vote for a segment.
- The sum of the fractional affirmative votes from all segments divided by the number of segments voting will be used to determine if a two-thirds majority has been achieved. (A segment will be considered as "voting" if any member of the segment in the ballot pool casts either an affirmative or a negative vote.)
- A standard will be approved if the sum of fractional affirmative votes from all segments divided by the number of voting segments is greater than two thirds.

Each member of the ballot pool may vote on one of the following positions:

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[4] If a quorum of the ballot pool is not established, the standard will be balloted a second time, allowing a 15-business day period for the ballot. Should a quorum not be established with the second ballot, the standards process manager would re-survey the Registered Ballot Body to establish interest in participating in a ballot on the standard in accordance with the procedures in this manual. A re-ballot of the standard will take place with the revised standard ballot pool.

- Affirmative
- Affirmative, with comment
- Negative, with or without reasons (the reasons for a negative vote may be given and if possible should include specific wording or actions that would resolve the objection)
- Abstain

Members of the ballot pool should submit any comments on the proposed standard during the public comment period. If any comments are received during the ballot period, they shall be addressed in accordance with Step 8 and included with the recirculation ballot. The standards process manager shall facilitate the standard drafting team, assisted by the requester, in preparing a response to all votes submitted with reasons. The member submitting a vote with reasons will determine if the response provided satisfies those reasons. In addition, each objector shall be informed that an appeals process exists within the NERC standards process. A negative vote that does not contain a statement of reason does not require a response.

If there are no negative votes with reasons from the first ballot, then the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, regardless whether those reasons are resolved or not, a second ballot shall be conducted.

Second Ballot

In the second ballot (also called a “re-circulation ballot”), members of the ballot pool 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 ballot pool shall be permitted to reconsider and change their vote from the first ballot. Members of the ballot pool that did not respond to the first ballot shall be permitted to vote in the second ballot. 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 once again ten days. The 30-day posting is not required for the second ballot. Members of the ballot pool may submit comments in the second ballot but no response 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 SAC 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 standards process manager 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 consensus standard will be posted and presented to the Board of Trustees for adoption by NERC.

Step 10 — Adoption of the Reliability Standard by the Board

Objective: *To have the Board of Trustees adopt the standard as a NERC standard, and adopt the associated implementation plan.*

Sequence Considerations: *The 30-day notice prior to action by the Board of Trustees may begin concurrently with or any time after the start of the first ballot. The 30-day period shall not end any sooner than the end of the final ballot.*

A reliability standard submitted for adoption by the Board of Trustees must be publicly posted and noticed at least 30 days prior to action by the Board of Trustees. At a regular or special meeting, the Board of Trustees shall consider adoption of the proposed reliability standard. The board shall consider the results of the balloting and dissenting opinions. The board shall consider any advice offered by the NERC Stakeholders Committee. The board shall adopt or reject a standard, but may not modify a proposed reliability standard. If the board chooses not to adopt a standard, it shall provide its reasons for not doing so.

A reliability standard that is adopted by the board shall become effective on a date designated by the board in accordance with the implementation plan. The standard will be publicly posted, showing the final status.

Step 11 — Implementation of Reliability Standard

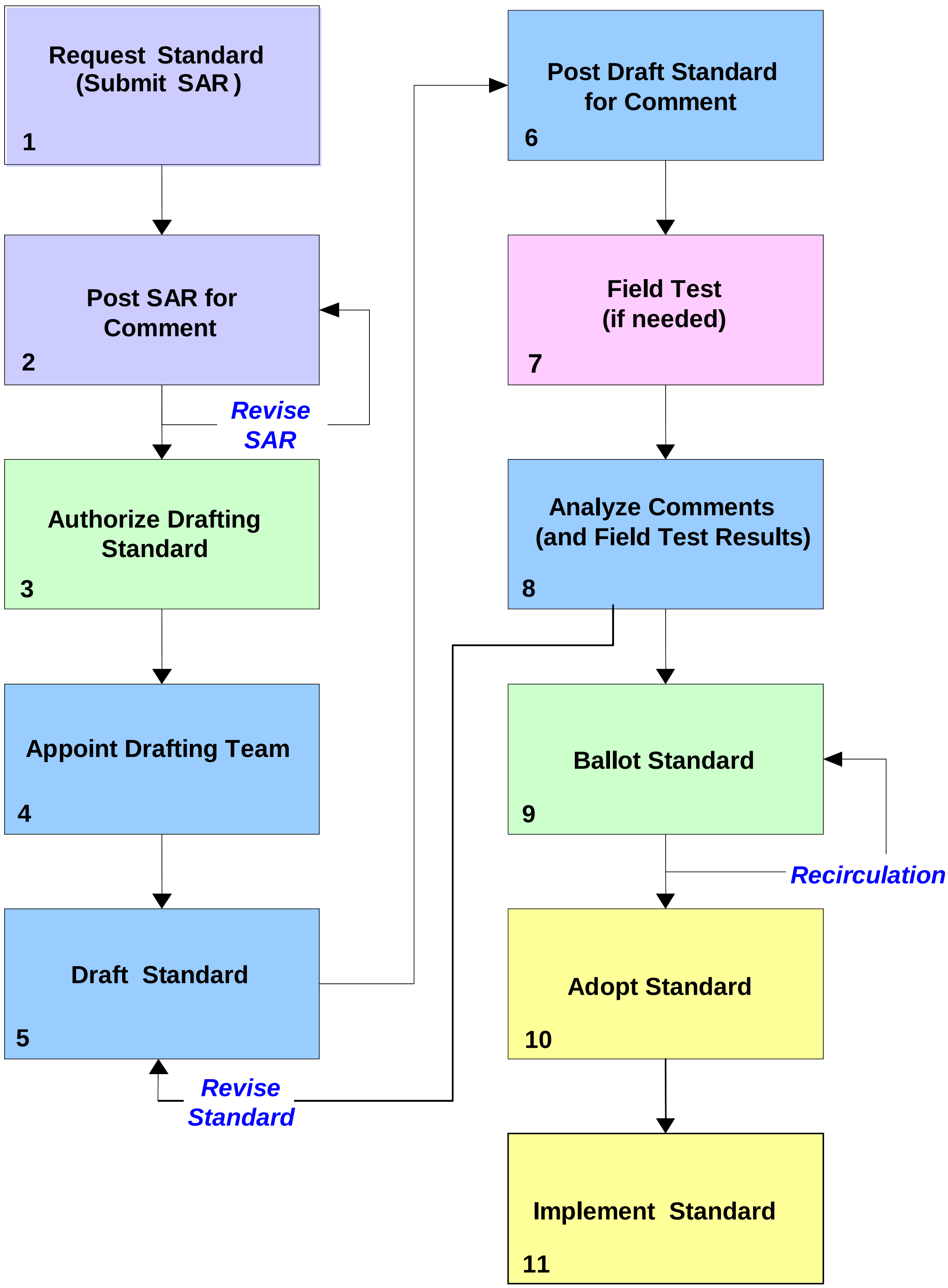
Objective: *Industry stakeholders use the standard and the compliance program incorporates the standard into its compliance monitoring and enforcement.*

Sequence Considerations: *The effective date of a standard is approved as part of the standard implementation plan and shall not be sooner than adoption by the Board.*

Once a reliability standard is adopted and made effective in accordance with the implementation plan, all persons and organizations subject to the bylaws of NERC are required to comply with the standard in accordance with those bylaws and other applicable agreements. The Board of Trustees has established a separate compliance program to measure compliance with the standards and administer sanctions as appropriate. After adoption of a NERC reliability standard, the standard will be forwarded to the compliance program for compliance monitoring and enforcement.

Reliability standards may, at the discretion of the board, be filed with applicable regulatory agencies in the United States, Canada, and Mexico.

Process Diagram



Special Procedures

Urgent Actions

Under certain conditions, the SAC may designate a proposed standard or revision to a standard as requiring urgent action. Urgent action may be appropriate when a delay in implementing a proposed standard or revision can materially impact reliability of the bulk electric systems. The SAC must use its judgment carefully to ensure an urgent action is truly necessary and not simply an expedient way to change or implement a standard.

A requester prepares a SAR and a draft of the proposed standard and submits it to the standards process manager. The SAR must include a justification for urgent action. The standards process manager submits the request to the SAC for its consideration. If the SAC designates the requested standard or revision as an urgent action item, then the standards process manager shall immediately seek participants for a ballot pool (as described in Step 3 of the process) and shall post the draft. This posting requires a minimum 30-day posting period before the ballot and applies the same voting procedure as described in Step 9.

Any standard approved as an urgent action shall have a termination date specified that shall not exceed one year from the approval date. Should there be a need to make the standard permanent, then the standard would be required to go through the full consensus process.

Urgent actions that expire may be renewed using the urgent action process again, in the event a permanent standard is not adopted. In determining whether to authorize an urgent action standard for a renewal ballot, the SAC shall consider the impact of the standard on the reliability of the bulk electric system and whether expeditious progress is being made toward a permanent replacement standard. The SAC shall not authorize a renewal ballot if there is insufficient progress toward adopting a permanent replacement standard or if the SAC lacks confidence that a reasonable completion date is achievable. The intent is to ensure that an urgent action standard does not in effect take on a degree of permanence due to the lack of an expeditious effort to develop a permanent replacement standard. With these principles, there is no predetermined limit on the number of times an urgent action may be renewed. However, each urgent action standard renewal shall be effective only upon approval by a ballot pool and adoption by the Board.

Any person or entity, including the drafting team working on a permanent replacement standard, may at any time submit a SAR proposing that an urgent action standard become a permanent standard by following the full standards process.

Interpretations of Standards

All persons who are directly and materially affected by the reliability of the North American bulk electric systems shall be permitted to request an interpretation of the standard. The person requesting an interpretation will send a request to the standards process manager explaining the specific circumstances surrounding the request and what clarifications are required as applied to those circumstances. The request 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 standards process manager will assemble a team with the relevant expertise to address the clarification. The standards process manager shall also form a ballot pool.

As soon as practical (not more than 45 days), the team will draft a written interpretation to the standard addressing the issues raised. Balloting shall take place as described in Step 9 of this manual. If approved, the interpretation is appended to the standard and is effective immediately. The interpretation will stand until such time as the standard is revised through the normal process, at which time the standard will be modified to incorporate the clarifications provided by the interpretation.

Regional Differences

A regional difference is an aspect of a NERC reliability standard that applies only within a given region or regions. A regional difference may be used, for example, to exempt a particular region from all or a portion of a NERC reliability standard that does not apply in that region. A regional difference may establish different measures or performance criteria as necessary to achieve reliability within that region.

To the maximum extent feasible, regional differences should be addressed through the NERC standards process and incorporated into and approved as part of the NERC reliability standard. In all cases, if a requirement would otherwise be inconsistent with or less stringent than a NERC reliability standard, then that regional difference shall be made part of the NERC reliability standard.

Regional differences should be identified and considered when the SAR is posted for comment. Regional differences should also be considered in the drafting of a standard, with the intent to make any necessary regional differences a part of the standard. Public comments on the draft standard provide a second opportunity to ensure necessary regional differences have been accommodated in the draft. The public posting also allows for all impacted parties to identify the requirements of a NERC reliability standard as applied within all regions and interconnections.

Regional differences that are proposed to be made part of a NERC reliability standard shall be considered during the NERC standards process in accordance with the criteria for regional standards and regional differences section below. These criteria provide that:

- Interconnection-wide regional differences are presumed to be valid, and there is a burden of proof to demonstrate otherwise in accordance with the stated criteria; and
- Regional differences that are not applied on an interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid in accordance with the stated criteria.

Regional Standards

Regions may develop, through their own processes, separate regional standards that go beyond, add detail to, or implement NERC reliability standards, or that cover matters not addressed in NERC reliability standards. Regional standards may be developed and exist separately from NERC reliability standards, or may be proposed as NERC reliability standards. Regional standards that exist separately from NERC reliability standards shall not be inconsistent with or less stringent than NERC reliability standards.

A regional standard that is proposed to be made a NERC reliability standard shall be considered during the NERC standards process in accordance with the criteria for regional standards and regional differences section below. These criteria provide that:

- Interconnection-wide regional standards are presumed to be valid, and there is a burden of proof to demonstrate otherwise in accordance with the stated criteria; and
- Regional standards that are not applied on an interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid in accordance with the stated criteria.

Criteria for Regional Standards and Regional Differences

Proposals for regional standards or regional differences that are intended to apply on an interconnection-wide basis shall be presumed to be valid and included in a NERC reliability standard unless there is a clear demonstration within the NERC standards process that the proposed regional standard or regional difference:

- Was not developed in a fair and open process that provided an opportunity for all interested parties to participate;
- Would have a significant adverse impact on reliability or commerce in other Interconnections;
- Fails to provide a level of reliability of the bulk electric system within the interconnection such that the regional standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security; or
- Would create a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability.

Proposals for regional standards or regional differences that are intended to apply only to part of an Interconnection will be included in a NERC reliability standard only if the proponent demonstrates that the proposed regional standard or regional difference:

- Was developed in a fair and open process that provided an opportunity for all interested parties to participate;
- Would not have an adverse impact on commerce that is not necessary for reliability;
- Provides a level of bulk electric system reliability that is adequate to protect public health, safety, welfare, and national security and would not have a significant adverse impact on reliability; and
- Is based on a justifiable difference between regions or between subregions within the regional organization's geographic area.

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, reaffirmation, or withdrawal of a reliability standard shall have the right to appeal. This appeals process applies only to the NERC 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 submits to the standards process manager a complaint in writing 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 standards process manager 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 will 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, as indicated by the appellant in writing to the standards process manager, the standards process manager shall convene a Level 2 Appeals Panel. This panel shall consist of five members total appointed by the Board of Trustees. In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The standards process manager 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 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 SAC with a statement of the issues and facts in regard to which fair and equitable action was not taken. The panel may find against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections. The panel may not, however, revise, approve, disapprove, or adopt a reliability standard, as these responsibilities remain with the standard's ballot pool and Board of Trustees respectively. The actions of the Level 2 Appeals Panel shall be publicly posted.

In addition to the foregoing, a procedural objection that has not been resolved may be submitted to the Board of Trustees for consideration at the time the board decides whether to adopt a particular reliability standard. 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 ballot pool on the reliability standard in question.

Maintenance of Reliability Standards and Process

Parliamentary Procedures

Except as required by this manual or other NERC documents, all meetings conducted as part of the standards process shall be guided by the latest version of Robert's Rules of Order.

Process Revisions

Requests to Revise the Reliability Standards Process Manual

Any person or entity, including the SAC, may submit a written request to modify the reliability standards Process Manual. The SAC shall oversee the handling of the request. The SAC shall prioritize all requests, merge related requests, and respond to each requestor within 90 days. The SAC shall classify each request into one of two types: 1) a procedural/administrative revision, or 2) a change affecting one or more "fundamental tenets" (described later).

Abbreviated Process for Procedural/Administrative Changes

The SAC shall handle all procedural/administrative requests using an abbreviated process described here. The SAC shall post all proposed procedural/administrative revisions to the reliability standards Process Manual for a 30-day public comment period. The SAC shall consider all comments received and modify the proposed revisions as needed. Based on the degree of consensus for the revisions, the SAC may:

a. Submit the revised manual directly to the board for adoption;

b. Submit the revised manual for ballot pool approval prior to submitting it for board adoption (the regular voting process in the manual, including a recirculation ballot if needed, would be used and the results of the ballot would be binding on the decision to move the revisions to the board or not);

c. Propose additional changes and repeat the posting for additional comments;

d. Remand the proposal to the requester for further work; or

e. Reject the proposal.

f. The SAC shall post any proposed revisions submitted for board adoption for a period of 30 days prior to board action. The SAC shall submit to the board a description of the basis for the manual changes, a summary of the comments received, and any minority views expressed in the comment process. The proposed manual revisions will be effective upon board adoption, or another date designated by the board.

Fundamental Tenets

Certain provisions of the Reliability Standards Process Manual are considered fundamental tenets and shall be handled using the full approval process described below. These fundamental tenets shall be modifiable only by approval of the Registered Ballot Body as indicated by vote of a ballot pool. These fundamental tenets include the following:

- Purpose (page 4)

- Authority (page 4)
- Definition of a reliability standard (page 6)
- Characteristics of a reliability standard (page 6)
- Elements of a reliability standard (page 6)
- Registered ballot body (page 10)
- Ballot pool (page 10)
- Subcommittees, working groups, and task forces (page 11)
- Definitions of due process, openness, and balance (page 13)
- Step 9 – Ballot the new or revised standard (pages 20-22)
- Step 10 – Adoption of the reliability standard by the board (page 22)
- Urgent actions (page 24)
- Regional differences (pages 25)
- Regional standards (page 25)
- Criteria for regional differences (pages 25-26)
- Appeals process (pages 26-27)
- Process revisions (page 28-30)
- Registration procedures (page 38)
- Segment qualification guidelines (pages 38-39)
- Stakeholder segments (page 39-40)

Process for Changing Fundamental Tenets

When proceeding with a proposed revision to the Standards Process Manual affecting one or more fundamental tenets, the SAC shall use a full approval process. The SAC shall post the proposed revisions for a 45-day public comment period. Based on the degree of consensus for the revisions, the SAC may:

a. Submit the revised manual for ballot pool approval;
b. Repeat the posting for additional inputs after making changes based on comments received;
c. Remand the proposal to the requester for further work; or
d. Reject the proposal.

The Registered Ballot Body shall be represented by a ballot pool formed when the proposed revisions are first posted for comment. The ballot procedure shall be the same as that defined for approval of a standard, including the use of a recirculation ballot if needed. If the proposed revision is approved by the ballot pool, the SAC shall submit the revised manual to the board for adoption. The SAC shall post any proposed revisions submitted for board adoption for a period of 30 days prior to board action. The SAC shall submit to the board a description of the basis for the manual changes, a summary of the comments received, and any minority views expressed in the comment and ballot process. The proposed manual revisions will be effective upon board adoption, or another date designated by the board.

The Board of Trustees endorsed the industry segments and weighted segment voting model described in Appendix B of the Reliability Standards Process Manual and reserves the right to change the segments and the weighted segment voting model from time to time at its discretion. This does not preclude others from requesting a change to the segments or weighted segment voting model through the process described here.

Appeals

Persons who have directly or materially affected interests and who have been or will be adversely affected by any substantive or procedural action or inaction related to revision of the Reliability Standards Process Manual shall have the right to appeal, using the process described under appeals.

Filing of Revisions with ANSI

NERC staff shall submit revisions to the Reliability Standards Process Manual to ANSI as needed to maintain NERC's status as an ANSI-accredited standards developer.

Standards Process Accreditation

NERC shall seek continuing ANSI accreditation of the standards process defined by this manual. The standards process manager shall be responsible for administering the accreditation application and maintenance process.

Five-Year Review

Each reliability standard shall be reviewed at least once every five years from the effective date of the standard or the latest revision to the standard, whichever is later. The review process shall be conducted in accordance with Steps 6, 8, and 9 of the standards process. As a result of this review, a reliability standard shall be reaffirmed, revised, or withdrawn. If this review indicates a need to revise or delete the standard, a SAR shall be prepared and submitted in accordance with the standards process. The standard process manager shall be responsible for administration of the five-year review of reliability standards.

Filing of Reliability Standards with Regulatory Agencies

At the discretion of the Board of Trustees, adopted reliability standards may be filed with applicable regulatory agencies in the United States, Canada, and Mexico.

On-line Standards Information System

The standards process manager shall be responsible for maintaining an electronic database of information regarding currently proposed and currently in effect 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 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 standards process manager shall be responsible for maintaining a historical record of reliability standards information that is no longer maintained on-line. For example, standards that expired or were replaced may be removed from the on-line system. Also, SARs that are no longer being considered in the standards process may be placed in the archived records. Archived information shall be retained indefinitely as practical, but in no case less than five years or one complete standard cycle from the date on which the standard was no longer in effect. Archived records of standards information shall be available electronically within 30 days following the receipt by the standards process manager of a written request.

Numbering System

The standards process manager shall establish and maintain a system of identification numbers that allow reliability standards to be categorized and easily referenced.

Supporting Documents

The following documents may be developed to support a 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 shall be incorporated into the standard. For example, a procedure that must be followed as written must be incorporated into a 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 a reliability standard.	Standing Committee
Standard Supplement	Data forms, pro forma documents, and associated instructions that support the implementation of a reliability standard.	Standing Committee
Procedure	Step-wise instructions defining a particular process or operation. Procedures may support the implementation of a reliability standard or satisfy another purpose consistent with the reliability and market interface principles.	Standing Committee
Practice	A convention of behavior. Practices may support the implementation of a reliability standard or satisfy another purpose consistent with the reliability and market interface principles.	Standing Committee
Training Reference	Training materials that may support the implementation of a reliability standard or satisfy another purpose consistent with the reliability and market interface principles.	Standing Committee
Technical Reference	Descriptive, technical information or analysis. A technical reference may support the implementation of a reliability standard or satisfy another purpose consistent with the reliability and market interface principles.	Standing Committee
White Paper	An informal paper stating a position or concept. A white paper may be used to propose preliminary concepts for a standard or one of the documents above.	Standing Committee approves for publication with no implied approval of the concepts or positions in the white paper.

Appendix A – Information in a Standard Authorization Request

The table below provides a representative example[5] of information in a Standard Authorization Request. The standards process manager shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards process. Standard Authorization Request Form

Title of Proposed Standard:
Request Date:

SAR Requestor Information

Name:	***SAR Type (Check box for one of these selections.)***	
Company:	☐	New Standard
Telephone:	☐	Revision to Existing Standard
Fax:	☐	Withdrawal of Existing Standard
Email:	☐	Urgent Action

Purpose (*Describe the purpose of the proposed 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.****)***

[5] The latest version of this form can be downloaded from the NERC standards development web page:

http://www.nerc.com/~filez/sar.html

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	Ensures the reliability of the bulk transmission system within its reliability authority area. This is the highest reliability authority.
☐	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
☐	Planning Authority	Plans the bulk electric system
☐	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	Owns and operates generation unit(s) or runs a market for generation products that performs the functions of supplying energy and interconnected operations services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary interconnected operations services as required
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles (Check box for all that apply.)

☐	1. Interconnected bulk electric 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 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 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 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 systems.

☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored, and maintained on a wide-area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. A reliability standard shall not give any market participant an unfair competitive advantage.Yes
3. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
4. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
5. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

Related Standards

Standard No.	*Explanation*

Related SARs

SAR ID	*Explanation*

Regional Differences

Region	***Explanation***
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MRO	
NPCC	
SERC	
SPP	
WECC	

Appendix B – Development of the Registered Ballot Body[6]

Registration Procedures

The Registered Ballot Body comprises all organizations and entities that:

1. Qualify for one of the segments, and
2. Are registered with NERC as potential ballot participants in the voting on standards, and
3. Are current with any designated fees.

Each participant, when initially registering to join the Registered Ballot Body, and annually thereafter, will self-select to belong to one of the segments described above.

NERC general counsel will review all applications for joining the Registered Ballot Body, 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 SAC will decide disputes, with an appeal to the Board of Trustees.

All registrations will be done electronically.

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.

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 and is represented by a different representative.
- Corporations, organizations, and entities may participate freely in all subgroups.
- After their initial selection, registered participants may apply to change segments annually, according to a defined schedule.
- The qualification guidelines and rules for joining segments will be reviewed periodically to ensure that the process continues to be fair, open, balanced, and inclusive. Public input will 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, NERC must have in its possession, either in writing or by

[6] This description is from the final report of the NERC Standing Committees Representation Task Force, February 7, 2002. The Board of Trustees endorsed the industry segments and weighted segment voting model described within this document on February 20, 2002 and may change this from time to time. The latest version (approved or endorsed by the NERC Board of Trustees) shall be used in the NERC Standards Development Process.

email, documentation that the voting right by proxy has been transferred from the registered participant to the agent.

Initial Segments

Segment 1. Transmission Owners

a. Any entity 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 that have placed their transmission under the operational control of an RTO.

c. Independent transmission companies or organizations, merchant transmission developers, and transcos that are not RTOs.

d. Excludes RTOs and ISOs (that are eligible to belong to Segment 2).

Segment 2. Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), and Regional Reliability Organizations (RROs)

a. Authorized by appropriate regulator to operate as RTO or ISO.

b. Regional reliability organizations that are members of NERC.

c. In cases where the RTO or ISO and the RRO have exactly the same geographic boundary, both may belong to this segment as long as they are separate entities.

Segment 3. Load-Serving Entities (LSEs)

a. Entities serving end-use customers under a regulated tariff, a contract governed by a regulatory tariff, or other legal obligation to serve.

b. A member 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. Transmission Dependent Utilities (TDUs)

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 associations can represent groups of TDUs.

Segment 5. Electric Generators

a. Affiliated and independent generators.

b. A corporation that sets up separate corporate entities for each one or two generating plants 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 6. 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 an electricity broker, aggregator, or marketer function are permitted to belong to this segment.

Segment 7. Large Electricity End Users

a. At least one service delivery taken at 50 kV (radial supply or facilities dedicated to serve customers) that is not purchased for resale.

b. A single customer with an average aggregated service load (not purchased for resale) of at least 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility.

c. Agents or associations can represent groups of large end users.

Segment 8. Small Electricity Users

a. Service taken at below 50 kV.

b. A single customer with an average aggregated service load (not purchased for resale) of less than 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility.

c. Agents, state consumer advocates, or other advocate groups can represent groups of small customers.

Segment 9. Federal, State, and Provincial Regulatory or other Government Entities

a. Does not include federal power management agencies or the Tennessee Valley Authority.

b. May include public utility commissions.

Appendix C – Examples of Weighted Segment Voting Calculation

(Assumptions on numbers of entities are purely hypothetical and used only for illustrative purposes.)

Ballot Body and Pools

Segment	*Registered Ballot Body*	*ballot pools*	
		Standard #1	*Standard #2*
1. Transmission Owners	300	250	100
2. RTOs, ISOs, and RROs	20	20	20
3. LSEs	200	100	50
4. TDUs	100	75	50
5. Electric Generators	25	20	25
6. Brokers, Aggregators, and Marketers	10	10	10
7. Large End-Use Customers	5	1	4
8. Small End-Use Customers	25	10	5
9. Regulators or Other Government Entities	50	10	15
Totals	**735**	**496**	**279**

Example 1

Segment	*ballot pool*	*Votes*				*Abstain*	*No Ballot*
		Affirmative		*Negative*			
		# Votes	Fraction	# Votes	Fraction	# Votes	
1	250	200	0.833	40	0.167	10	0
2	20	15	0.750	5	0.250	0	0
3	100	60	0.632	35	0.368	5	0
4	75	50	0.714	20	0.286	0	5
5	20	7	0.412	10	0.588	2	1
6	10	6	0.600	4	0.400	0	0
7	1	0		0		1	0
8	10	0		0		0	10
9	10	8	0.800	2	0.200	0	0
Totals	**496**	**346**	**4.741**	**116**	**2.259**	**18**	**16**
Ballots	**480**	**96.8%**					
Wtd Vote			**0.677**		**0.323**		

Weighted segment vote is greater than two thirds AND more than 75% of the Standard ballot pool returned a ballot. Standard is approved.

No "Affirmative" or "Negative" votes cast, so segments not counted in total weighting.

Percent ballots returned
= (480/496) x 100
= 96.6%

Weighted segment vote
= (Total Fraction) / (Segments Counted)
= 4.741 / 7

Example 2

Weighted segment vote is greater than two thirds BUT less than 75% of the Standard ballot pool returned a ballot. Standard is NOT approved.

Segment	*ballot pool*	*Votes*				*Abstain*	*No Ballot*
		Affirmative		*Negative*			
		# Votes	Fraction	# Votes	Fraction	# Votes	
1	100	25	1.000	0	0.000	0	75
2	20	15	0.750	5	0.250	0	0
3	50	30	0.600	20	0.400	0	0
4	50	25	0.833	5	0.167	0	20
5	25	18	0.783	5	0.217	2	0
6	10	6	0.600	4	0.400	0	0
7	4	4	1.000	0	0.000	0	0
8	5	5	1.000	0	0.000	0	0
9	15	7	1.000	0	0.000	5	3
Total	**279**	**135**	**7.566**	**39**	**1.434**	**7**	**98**
Ballots	**181**	**64.87%**					
Wtd Vote			**0.841**		**0.159**		

Exhibit D — Analysis of Regional "Fill-in-the-Blank" Standards

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
BAL-002-0	R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: R 2.1. The minimum reserve requirement for the group. R 2.2. Its allocation among members. R 2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve. R 2.4. The procedure for applying Contingency Reserve in practice. R 2.5. The limitations, if any, upon the amount of interruptible load that may be included. R 2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.	R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.
EOP-004-0	R1. Each Regional Reliability Organization shall establish and maintain a regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.	R3.4 If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall prepare this report within

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
		60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.
EOP-007-0	R1. Each Regional Reliability Organization shall establish and maintain a system [Black Start Capability Plan], as part of an overall coordinated Regional System Restoration Plan]. The Regional SRP shall include requirements for verification through analysis how system black start generating units shall perform their intended functions and shall be sufficient to meet SRP expectations. The Regional Reliability Organization shall coordinate with and among other Regional Reliability Organizations as appropriate in the development of its BCP. The BCP shall include: R 1.1. A requirement to have a database that contains all blackstart generators designated for use in an SRP within the respective areas. This database shall be updated on an annual basis. The database shall include the name, location, megawatt capacity, type of unit, latest date of test, and starting method. R 1.2. A requirement to demonstrate that blackstart units perform their intended functions as required in the Regional SRP. This requirement can be met through either	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	simulation or testing. The BCP must consider the availability of designated BCP units and initial transmission switching requirements. R 1.3. Blackstart unit testing requirements including, but not limited to: R 1.3.1. Testing frequency (minimum of one third of the units each year). R 1.3.2. Type of test required, including the requirement to start when isolated from the system. R 1.3.3. Minimum duration of tests. R 1.4. A requirement to review and update the Regional BCP at least every five years. R2. The Regional Reliability Organization shall provide documentation of its system BCPs to NERC within 30 calendar days of a request.	
EOP-009-0		R1. The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.
FAC-001-0		The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
		connection requirements shall address connection requirements for: R 1.1. Generation facilities, R 1.2. Transmission facilities, and R 1.3. End-user facilities
FAC-002-0		R1. The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include: R 1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems. R 1.2. Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements. R 1.3. Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved. R 1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0.

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
		R 1.5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.
FAC-004-0		The Transmission Owner and Generator Owner shall each document the methodology(ies) used to determine its electrical equipment and Facility Rating. Further, the methodology(ies) shall comply with applicable Regional Reliability Organization requirements. The documentation shall address and include: R 1.1. The methodology(ies) used to determine equipment and Facility Rating of the items listed for both normal and emergency conditions: R 1.1.1. Transmission circuits. R 1.1.2. Transformers. R 1.1.3. Series and shunt reactive elements. R 1.1.4. Terminal equipment (e.g., switches, breakers, current transformers, etc). R 1.1.5. VAR compensators. R 1.1.6. High voltage direct current converters. R 1.1.7. Any other device listed as a Limiting Element. R 1.2. The Rating of a facility shall not exceed the Rating(s) of the most Limiting Element(s) in the circuit, including terminal connections and associated equipment. R 1.3. In cases where protection systems and control settings constitute a loading limit on a facility, this limit shall become the Rating for that facility.

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
		R 1.4. Ratings of jointly-owned and jointly-operated facilities shall be coordinated among the joint owners and joint operators resulting in a single set of Ratings. R 1.5. The documentation shall identify the assumptions used to determine each of the equipment and Facility Ratings, including references to industry Rating practices and standards (e.g., ANSI, IEEE, etc.). Seasonal Ratings and variations in assumptions shall be included.
IRO-001-0	R1. Each Regional Reliability Organization, sub-region, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.	
MOD-001-0	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional TTC and ATC methodology. (Certain systems that are not required to post ATC values are exempt from this standard.) The Regional Reliability Organization's TTC and ATC methodology shall include each of the following nine items, and shall explain its use in determining TTC and ATC values: R 1.1. A narrative explaining how TTC and ATC values are determined. R 1.2. An accounting for how the reservations and	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional TTC and ATC methodology. (Certain systems that are not required to post ATC values are exempt from this standard.) The Regional Reliability Organization's TTC and ATC methodology shall include each of the following nine items, and shall explain its use in determining TTC and ATC values: R 1.1. A narrative explaining how TTC and ATC values are determined. R 1.2. An accounting for how the reservations and

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the Transmission Service Provider's system, are included. R 1.3. An accounting for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations. R 1.4. A description of how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or because the reservations have not all been made.) R 1.5. A requirement that TTC and ATC values shall be determined and posted as follows: R 1.5.1. Daily values for current week at least once per day. R 1.5.2. Daily values for day 8 through the first month at least once per week. R 1.5.3. Monthly values for months 2 through 13 at least once per month. R 1.6. Indication of the treatment and level of customer demands, including interruptible demands.	schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the Transmission Service Provider's system, are included. R 1.3. An accounting for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations. R 1.4. A description of how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or because the reservations have not all been made.) R 1.5. A requirement that TTC and ATC values shall be determined and posted as follows: R 1.5.1. Daily values for current week at least once per day. R 1.5.2. Daily values for day 8 through the first month at least once per week. R 1.5.3. Monthly values for months 2 through 13 at least once per month. R 1.6. Indication of the treatment and level of customer demands, including interruptible demands.

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	R 1.7. A specification of how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by Transmission Service Providers for the calculation of TTC and ATC values are shared and used within the Regional Reliability Organization and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regional Reliability Organizations. In addition, specify how this information is to be used to determine TTC and ATC values. If some data is not used, provide an explanation. R 1.8. A description of how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons. R 1.9. A description of the Regional Reliability Organization's practice on the netting of transmission reservations for purposes of TTC and ATC determination.	R 1.7. A specification of how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by Transmission Service Providers for the calculation of TTC and ATC values are shared and used within the Regional Reliability Organization and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regional Reliability Organizations. In addition, specify how this information is to be used to determine TTC and ATC values. If some data is not used, provide an explanation. R 1.8. A description of how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons. R 1.9. A description of the Regional Reliability Organization's practice on the netting of transmission reservations for purposes of TTC and ATC determination.
MOD-002-0	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to periodically review (at least annually) and ensure that the TTC and ATC calculations and resulting values of member Transmission Service Providers comply with the Regional TTC and ATC	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to periodically review (at least annually) and ensure that the TTC and ATC calculations and resulting values of member Transmission Service Providers comply with the Regional TTC and ATC

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	methodology and applicable Regional criteria.	methodology and applicable Regional criteria.
MOD-003-0	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a procedure on how transmission users can input their concerns or questions regarding the TTC and ATC methodology and values of the Transmission Service Provider(s), and how these concerns or questions will be addressed. The Regional Reliability Organization's procedure shall specify the following: R 1.1. The name, telephone number and email address of a contact person to whom concerns are to be addressed. R 1.2. The amount of time it will take for a response. R 1.3. The manner in which the response will be communicated (e.g., email, letter, telephone, etc). R 1.4. What recourse a customer has if the response is deemed unsatisfactory. R2. The Regional Reliability Organization shall post on a web site that is accessible by the Regional Reliability Organizations, NERC, and transmission users, its procedure for receiving and addressing concerns about the TTC and ATC methodology and TTC and ATC values of member Transmission Service Providers.	
MOD-004-0	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional CBM methodology. The Regional	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional CBM methodology. The Regional

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	Reliability Organization's CBM methodology shall include each of the following ten items, and shall explain its use in determining CBM value. Other items that are Regional Reliability Organization specific or that are considered in each respective Regional Reliability Organization methodology shall also be explained along with their use in determining CBM values. R 1.1. Specify that the method used by each Regional Reliability Organization member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria. R 1.2. Specify the frequency of calculation of the generation reliability requirement and associated CBM values. R 1.3. Require that generation unit outages considered in a Transmission Service Provider's CBM calculation be restricted to those units within the Transmission Service Provider's system. R 1.4. Require that CBM be preserved only on the Transmission Service Provider's System where the Load-Serving Entity's Load is located (i.e., CBM is an import quantity only). R 1.5. Describe the inclusion or exclusion rationale for generation resources of each Load- Serving Entity including those generation resources not directly connected to the Transmission Service Provider's system but serving Load-Serving	Reliability Organization's CBM methodology shall include each of the following ten items, and shall explain its use in determining CBM value. Other items that are Regional Reliability Organization specific or that are considered in each respective Regional Reliability Organization methodology shall also be explained along with their use in determining CBM values. R 1.1. Specify that the method used by each Regional Reliability Organization member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria. R 1.2. Specify the frequency of calculation of the generation reliability requirement and associated CBM values. R 1.3. Require that generation unit outages considered in a Transmission Service Provider's CBM calculation be restricted to those units within the Transmission Service Provider's system. R 1.4. Require that CBM be preserved only on the Transmission Service Provider's System where the Load-Serving Entity's Load is located (i.e., CBM is an import quantity only). R 1.5. Describe the inclusion or exclusion rationale for generation resources of each Load- Serving Entity including those generation resources not directly connected to the Transmission Service Provider's system but serving Load-Serving

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	Entity loads connected to the Transmission Service Provider's system. R 1.6. Describe the inclusion or exclusion rationale for generation connected to the Transmission Service Provider's system but not obligated to serve Native/Network Load connected to the Transmission Service Provider's system. R 1.7. Describe the formal process and rationale for the Regional Reliability Organization to grant any variances to individual Transmission Service Providers from the Regional Reliability Organization's CBM methodology. R 1.8. Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources. R 1.9. Describe the inclusion or exclusion rationale for the loads of each Load-Serving Entity, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions). R 1.10. Describe the inclusion or exclusion rationale	Entity loads connected to the Transmission Service Provider's system. R 1.6. Describe the inclusion or exclusion rationale for generation connected to the Transmission Service Provider's system but not obligated to serve Native/Network Load connected to the Transmission Service Provider's system. R 1.7. Describe the formal process and rationale for the Regional Reliability Organization to grant any variances to individual Transmission Service Providers from the Regional Reliability Organization's CBM methodology. R 1.8. Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources. R 1.9. Describe the inclusion or exclusion rationale for the loads of each Load-Serving Entity, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions). R 1.10. Describe the inclusion or exclusion rationale

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	for generation reserve sharing arrangements in the CBM values. R2. The Regional Reliability Organization shall make the most recent version of the documentation of its CBM methodology available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.	for generation reserve sharing arrangements in the CBM values.
MOD-005-0	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review (at least annually) the CBM calculations and the resulting values of member Transmission Service Providers to ensure that they comply with the Regional Reliability Organization's CBM methodology. The procedure shall include the following four requirements: R 1.1. Indicate the frequency under which the verification review shall be implemented. R 1.2. Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to transmission users. R 1.3. Require review of the consistency of the Transmission Service Provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the components that comprise CBM are addressed	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review (at least annually) the CBM calculations and the resulting values of member Transmission Service Providers to ensure that they comply with the Regional Reliability Organization's CBM methodology. The procedure shall include the following four requirements: R 1.1. Indicate the frequency under which the verification review shall be implemented. R 1.2. Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to transmission users. R 1.3. Require review of the consistency of the Transmission Service Provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the components that comprise CBM are addressed

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. R 1.4. Require CBM values to be periodically updated (at least annually) and available to the Regional Reliability Organizations, NERC, and transmission users. R 2. Each Regional Reliability Organization shall document its CBM procedure and shall make its CBM review procedure available to NERC on request (within 30 calendar days). R 3. The Regional Reliability Organization shall provide documentation of the results of the most current implementation of its CBM review procedure to NERC on request (within 30 calendar days).	in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. R 1.4. Require CBM values to be periodically updated (at least annually) and available to the Regional Reliability Organizations, NERC, and transmission users.
MOD-008-0	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional TRM methodology. The Region's TRM methodology shall specify or describe each of the following five items, and shall explain its use, if any, in determining TRM values. Other items that are Region-specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining TRM values.	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional TRM methodology. The Region's TRM methodology shall specify or describe each of the following five items, and shall explain its use, if any, in determining TRM values. Other items that are Region-specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining TRM values.

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	R 1.1. Specify the update frequency of TRM calculations. R 1.2. Specify how TRM values are incorporated into Available Transfer Capability calculations. R 1.3. Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. Any component of uncertainty, other than those identified in MOD-008-0_R 1.3.1 through MOD-008-0_R 1.3.7, shall benefit the interconnected transmission systems as a whole before they shall be permitted to be included in TRM calculations. The components of uncertainty identified in MOD-008-0_R 1.3.1 through MOD-008-0_R 1.3.7, if applied, shall be accounted for solely in TRM and not CBM. R 1.3.1. Aggregate Load forecast error (not included in determining generation reliability requirements). R 1.3.2. Load distribution error. R 1.3.3. Variations in facility Loadings due to balancing of generation within a Balancing Authority Area. R 1.3.4. Forecast uncertainty in transmission system topology. R 1.3.5. Allowances for parallel path (loop flow) impacts. R 1.3.6. Allowances for simultaneous path interactions.	R 1.1. Specify the update frequency of TRM calculations. R 1.2. Specify how TRM values are incorporated into Available Transfer Capability calculations. R 1.3. Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. Any component of uncertainty, other than those identified in MOD-008-0_R 1.3.1 through MOD-008-0_R 1.3.7, shall benefit the interconnected transmission systems as a whole before they shall be permitted to be included in TRM calculations. The components of uncertainty identified in MOD-008-0_R 1.3.1 through MOD-008-0_R 1.3.7, if applied, shall be accounted for solely in TRM and not CBM. R 1.3.1. Aggregate Load forecast error (not included in determining generation reliability requirements). R 1.3.2. Load distribution error. R 1.3.3. Variations in facility Loadings due to balancing of generation within a Balancing Authority Area. R 1.3.4. Forecast uncertainty in transmission system topology. R 1.3.5. Allowances for parallel path (loop flow) impacts. R 1.3.6. Allowances for simultaneous path interactions.

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	R 1.3.7. Variations in generation dispatch. R 1.3.8. Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window). R 1.4. Describe the conditions, if any, under which TRM may be available to the market as Non-Firm Transmission Service. R 1.5. Describe the formal process for the Regional Reliability Organization to grant any variances to individual Transmission Service Providers from the Regional TRM methodology. R2. The Regional Reliability Organization shall make its most recent version of the documentation of its TRM methodology available on a web site accessible by NERC, the Regional Reliability Organizations, and transmission users.	R 1.3.7. Variations in generation dispatch. R 1.3.8. Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window). R 1.4. Describe the conditions, if any, under which TRM may be available to the market as Non-Firm Transmission Service. R 1.5. Describe the formal process for the Regional Reliability Organization to grant any variances to individual Transmission Service Providers from the Regional TRM methodology.
MOD-009-0	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review Transmission Reliability Margin (TRM) calculations and resulting values of member Transmission Service Providers to ensure they comply with the Regional TRM methodology, and are periodically updated and available to transmission users. This procedure shall include the following four required elements: R 1.1. Indicate the frequency under which the verification review shall be implemented.	R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review Transmission Reliability Margin (TRM) calculations and resulting values of member Transmission Service Providers to ensure they comply with the Regional TRM methodology, and are periodically updated and available to transmission users. This procedure shall include the following four required elements: R 1.1. Indicate the frequency under which the verification review shall be implemented.

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	R 1.2. Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to transmission users. R 1.3. Require review of the consistency of the Transmission Service Provider's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. R 1.4. Require TRM values to be periodically updated (at least prior to each season — winter, spring, summer, and fall), as necessary, and made available to the Regional Reliability Organizations, NERC, and transmission users. R2. The Regional Reliability Organization shall make documentation of its Regional TRM review procedure available to NERC on request (within 30 calendar days). R3. The Regional Reliability Organization shall make documentation of the results of the most current implementation of its TRM review procedure available	R 1.2. Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to transmission users. R 1.3. Require review of the consistency of the Transmission Service Provider's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. R 1.4. Require TRM values to be periodically updated (at least prior to each season — winter, spring, summer, and fall), as necessary, and made available to the Regional Reliability Organizations, NERC, and transmission users.

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	to NERC on request (within 30 calendar days).	
MOD-010-0		R1. The Transmission Owners, Transmission Planners Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R 1. R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).
MOD-011-0	R1. The Regional Reliability Organizations within an Interconnection, in conjunction with the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate the development of the data requirements and reporting procedures for that Interconnection. The Interconnection-wide requirements shall include the following steady-state data requirements: R 1.1. Bus (substation): name, nominal voltage, electrical demand supplied (consistent with the aggregated and dispersed substation demand data supplied per Reliability Standards MOD-016-0, MOD-017-0, and MOD-020-0), and location. R 1.2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status. R 1.3. AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0) equipment status, and metering locations. R 1.4. DC Transmission Line (overhead and underground): line parameters, Normal and Emergency Ratings, control parameters, rectifier data, and inverter data.	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	R 1.5. Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0.), and equipment status. R 1.6. Reactive Compensation (shunt and series capacitors and reactors): nominal Ratings, impedance, percent compensation, connection point, and controller device. R 1.7. Interchange Schedules: Existing and future Interchange Schedules and/or assumptions. R2. The Regional Reliability Organizations within an Interconnection shall document their Interconnection's steady-state data requirements and reporting procedures, shall review those data requirements and reporting procedures (at least every five years), and shall make the data requirements and reporting procedures available on request (within five business days) to Regional Reliability Organizations, NERC, and all users of the interconnected transmission systems.	
MOD-012-0		R1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide appropriate equipment

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
		characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R 4. R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. If no schedule exists, then these entities shall provide data on request (30 calendar days).
MOD-013-0	R1. The Regional Reliability Organization, in coordination with its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. Each set of Interconnection-wide dynamics data requirements shall	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	include the following dynamics data requirements: R 1.1. Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment. R 1.1.1. Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990. R 1.1.2. The Interconnection-wide requirements shall specify unit size thresholds for permitting: The use of non-detailed vs. detailed models; The netting of small generating units with bus load, and; The combining of multiple generating units at one plant R 1.2. Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, and static compensators.	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	R 1.3. Dynamics data representing electrical demand characteristics as a function of frequency and voltage. R 1.4. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard MOD-010-0_R 1. R2. The Regional Reliability Organization shall participate in the documentation of its Interconnection's data requirements and reporting procedures and, shall participate in the review of those data requirements and reporting procedures (at least every five years), and shall provide those data requirements and reporting procedures to Regional Reliability Organizations, NERC, and all users of the Interconnected systems on request (within five business days).	
MOD-014-0	R1. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of solved (converged) Interconnection-specific steady-state system models. The Interconnection-specific models shall include near- and longer-term planning horizons that are representative of system conditions for projected seasonal peak, minimum, and other appropriate system demand levels. R2. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop steady-state system models annually for selected study	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	years, as determined by the Regional Reliability Organizations within its Interconnection. The Regional Reliability Organization shall provide the most recent solved (converged) Interconnection-specific steady-state models to NERC in accordance with each Interconnection's schedule for submission.	
MOD-015-0	R1. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of initialized (with no Faults or system Disturbances) Interconnection-specific dynamics system models linked to the steady-state system models, as appropriate, of Reliability Standard MOD-014-0_R 1. R2. The Regional Reliability Organization(s) within each Interconnection shall develop Interconnection dynamics system models for their Interconnection annually for selected study years as determined by the Regional Reliability Organization(s) within each Interconnection and shall provide the most recent initialized (approximately 25 seconds, no-fault) models to NERC in accordance with each Interconnection's schedule for submission.	
MOD-016-0	R1. The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	reliability analyses. R 1.1. The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005-0, TPL-006-0, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-0, MOD-014-0, MOD-015-0, MOD-016, MOD-017-0, MOD-018-0, MOD-019-0, MOD-020-0, and MOD-021-0. R 1.1. The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005-0, TPL-006-0, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-0, MOD-014-0, MOD-015-0, MOD-016, MOD-017-0, MOD-018-0, MOD-019-0, MOD-020-0, and MOD-021-0. R2. The documentation of the scope and details of the data reporting requirements shall be available on request (five business days).	
MOD-017-0		R1. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-0_R 1. R 1.1. Integrated hourly demands in MW (MW)

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		for the prior year. R 1.2. Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. R 1.3. Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years. R 1.4. Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the future, as requested.
MOD-019-0		R1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-0_R 1.
MOD-024-1	R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:	R3. The Generator Owner shall follow its Regional Reliability Organization’s procedures for verifying and reporting its gross and net Real Power generating capability per R1.

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	R 1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures. R 1.2. Criteria for reporting generating unit auxiliary loads. R 1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc. R 1.4. Periodicity and schedule of model and data verification and reporting. R 1.5. Information to be verified and reported: R 1.5.1. Seasonal gross and net Real Power generating capabilities. R 1.5.2. Real power requirements of auxiliary loads. R 1.5.3. Method of verification, including date and conditions.	
MOD-025-1	R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following: R 1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures. R 1.2. Criteria for reporting generating unit auxiliary loads.	R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its gross and net Reactive Power generating capability per R1.

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	R 1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of commissioning data, performance tracking, engineering analysis, testing, etc. R 1.4. Periodicity and schedule of model and data verification and reporting. R 1.5. Information to be reported: R 1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1. R 1.5.2. Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc. R 1.5.3. Verified Reactive Power of auxiliary loads. R 1.5.4. Method of verification, including date and conditions.	
PER-002-0		R3.1 A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
		operating positions.
PRC-002-0	R1. The Regional Reliability Organization shall develop comprehensive requirements for the installation of disturbance monitoring equipment to ensure data is available to determine system performance and the causes of system disturbances. The comprehensive requirements shall include all of the following: R 1.1. Type of data recording capability (e.g., sequence-of-event, Fault recording, dynamic Disturbance recording). R 1.2. Equipment characteristics including but not limited to: R 1.2.1. Recording duration requirements. R 1.2.2. Time synchronization requirements. R 1.2.3. Data format requirements. R 1.2.4. Event triggering requirements R 1.3. Monitoring, recording, and reporting capabilities of the equipment. R 1.3.1. Voltage. R 1.3.2. Current. R 1.3.3. Frequency. R 1.3.4. MW and/or MVAR, as appropriate. R 1.4. Data retention capabilities (e.g., length of time data is to be available for retrieval). R 1.5. Regional coverage requirements (e.g., by voltage, geographic area, electric area or subarea).	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	R 1.6. Installation requirements: R 1.6.1. Substations. R 1.6.2. Transmission lines. R 1.6.3. Generators. R 1.7. Responsibility for maintenance and testing. R 1.8. Requirements for periodic (at least every five years) updating, review, and approval of the Regional requirements. R2. The Regional Reliability Organization shall provide its requirements for the installation of disturbance monitoring equipment to other Regional Reliability Organizations and NERC on request (30 calendar days).	
PRC-003-1	R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements: R 1.1 The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on bulk power system reliability). R 1.2. Data reporting requirements (periodicity and format) for Misoperations. R 1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	R 1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures. R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations. R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.	
PRC-004-1		R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the

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		Regional Reliability Organization's procedures developed for PRC-003 R1. R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
PRC-006-0	Each Regional Reliability Organization shall develop, coordinate, and document an [Under-Frequency Load Shedding] program, which shall include the following: R 1.1. Requirements for coordination of UFLS programs within the subregions, Regional Reliability Organization and, where appropriate, among Regional Reliability Organizations. R 1.2. Design details shall include, but are not limited to: R 1.2.1. Frequency set points. R 1.2.2. Size of corresponding load shedding blocks (percent of connected loads.) R 1.2.3. Intentional and total tripping time delays. R 1.2.4. Generation protection. R 1.2.5. Tie tripping schemes. R 1.2.6. Islanding schemes. R 1.2.7. Automatic load restoration schemes.	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	R 1.2.8. Any other schemes that are part of or impact the UFLS programs. R 1.3. A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems. R 1.4. Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to: R 1.4.1. A review of the frequency set points and timing, and R 1.4.2. Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between Demand (Load) and generation. R2. The Regional Reliability Organization shall provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days).	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	R3. The Regional Reliability Organization shall provide documentation of the assessment of its UFLS program to NERC on request (within 30 calendar days).	
PRC-007-0		R1. The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements. R2. The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLSprogram database. R3. The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).
PRC-008-0		R1. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
		UFLS equipment testing, and the schedule for UFLS equipment maintenance. R2. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).
PRC-009-0		R1. The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to: R 1.1. A description of the event including initiating conditions. R 1.2. A review of the UFLS set points and tripping times. R 1.3. A simulation of the event. R 1.4. A summary of the findings. R2. The Transmission Owner, Transmission Operator,

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
		Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.
PRC-012-0	Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include: R 1.1. Description of the process for submitting a proposed SPS for Regional Reliability Organization review. R 1.2. Requirements to provide data that describes design, operation, and modeling of an SPS. R 1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0. R 1.4. Requirements to demonstrate that the	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	inadvertent operation of an SPS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0. R 1.5. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures. R 1.6. Regional Reliability Organization definition of misoperation. R 1.7. Requirements for analysis and documentation of corrective action plans for all SPS misoperations. R 1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure. R 1.9. Determination, as appropriate, of maintenance and testing requirements. R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its SPS review procedure on request (within 30 calendar days).	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
PRC-013-0	The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information: R 1.1. Design Objectives — Contingencies and system conditions for which the SPS was designed, R 1.2. Operation — The actions taken by the SPS in response to Disturbance conditions, and R 1.3. Modeling — Information on detection logic or relay settings that control operation of the SPS. R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	
PRC-014-0	R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all [Special Protection Systems] installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria. R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all SPSs installed in its Region to affected Regional Reliability Organizations or NERC on	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	request (within 30 calendar days). R3. The documentation of the Regional Reliability Organization's SPS assessment shall include the following elements: R 3.1. Identification of group conducting the assessment and the date the assessment was performed. R 3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed. R 3.3. Identification of SPSs that were found not to comply with NERC standards and Regional Reliability Organization criteria. R 3.4. Discussion of any coordination problems found between a SPS and other protection and control systems. R 3.5. Provide corrective action plans for non-compliant SPSs.	
PRC-015-0		R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R 1. R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
		Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service. R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).
PRC-016-0		R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R 1. R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations. R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
PRC-020-1	R1. The Regional Reliability Organization shall establish, maintain and annually update a database for UVLS programs implemented by entities within the Region to mitigate the risk of voltage collapse or voltage instability in the bulk power system. This database shall include the following items: R 1.1. Owner and operator of the UVLS program. R 1.2. Size and location of customer load, or percent of connected load, to be interrupted. R 1.3. Corresponding voltage set points and overall scheme clearing times. R 1.4. Time delay from initiation to trip signal. R 1.5. Breaker operating times. R 1.6. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems. R2. The Regional Reliability Organization shall provide the information in its UVLS database to the Planning Authority, the Transmission Planner, or other Regional Reliability Organizations and to NERC within 30 calendar days of a request.	
PRC-021-1		R1. Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the bulk power system shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
		Organization for each installed UVLS system: R1.1. Size and location of customer load, or percent of connected load, to be interrupted. R1.2. Corresponding voltage set points and overall scheme clearing times. R1.3. Time delay from initiation to trip signal. R1.4. Breaker operating times. R1.5. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems. R2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.
TOP-002-0		R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.
TOP-004-0		R3. Each Transmission Operator shall, when practical, operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by Regional Reliability Organization policy.

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
TPL-001-0		R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s). R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.
TPL-002-0		R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
		Organization.
TPL-003-0		R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.
TPL-004-0		R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.
TPL-005-0	Each Regional Reliability Organization shall annually conduct reliability assessments of its respective existing and planned Regional Bulk Electric System (generation and transmission facilities) for: R 1.1. Current year: R 1.1.1. Winter. R 1.1.2. Summer. R 1.1.3. Other system conditions as deemed appropriate by the Regional Reliability Organization. R 1.2. Near-term planning horizons (years one through five). Detailed assessments shall be conducted.	

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	R 1.3. Longer-term planning horizons (years six through ten). Assessment shall focus on the analysis of trends in resources and transmission Adequacy, other industry trends and developments, and reliability concerns. R 1.4. Inter-Regional reliability assessments to demonstrate that the performance of these systems is in compliance with NERC Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0 and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting Adequacy and Security. R2. The Regional Reliability Organization shall provide its Regional and Inter-Regional seasonal, near-term, and longer-term reliability assessments to NERC on an annual basis. R3. The Regional Reliability Organization shall perform special reliability assessments as requested by NERC or the NERC Board of Trustees under their specific directions and criteria. Such assessments may include, but are not limited to: R 3.1. Security assessments. R 3.2. Operational assessments. R 3.3. Evaluations of emergency response preparedness.	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	R 3.4. Adequacy of fuel supply and hydro conditions. R 3.5. Reliability impacts of new or proposed environmental rules and regulations. R 3.6. Reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the Adequacy of the interconnected Bulk Electric Systems in North America.	
TPL-006-0	R1. Each Regional Reliability Organization shall provide, as requested (seasonally, annually, or as otherwise specified) by NERC, system data, including past, existing, and future facility and Bulk Electric System data, reports, and system performance information, necessary to assess reliability and compliance with the NERC Reliability Standards and the respective Regional planning criteria. The facility and Bulk Electric System data, reports, and system performance information shall include, but not be limited to, one or more of the following types of information as outlined below: R 1.1. Electric Demand and Net Energy for Load (actual and projected demands and Net Energy for Load, forecast methodologies, forecast assumptions and uncertainties, and treatment of Demand-Side Management.) R 1.2. Resource Adequacy and supporting information (Regional assessment reports,	

Standard	Regional Criteria Requirement	Bulk Power System Owner, Operator, or User Requirements Dependent on Regional Criteria
	existing and planned resource data, resource availability and characteristics, and fuel types and requirements.) R 1.3. Demand-Side resources and their characteristics (program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations.) R 1.4. Supply-side resources and their characteristics (existing and planned generator units, Ratings, performance characteristics, fuel types and availability, and real and reactive capabilities.) R 1.5. Transmission system and supporting information (thermal, voltage, and Stability Limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems.) R 1.6. System operations and supporting information (extreme weather impacts, Interchange Transactions, and Congestion impacts on the reliability of the interconnected Bulk Electric Systems.) R 1.7. Environmental and regulatory issues and impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation.)	

Exhibit E — Development Record of Standards

The developmental record for the standards contained in Exhibit A fills 22 volumes and is over 10,000 pages. NERC will make this exhibit available electronically on a CD upon request. Alternatively, the record can be found at:
http://www.nerc.com/~filez/standards/Reliability_Standards.html