

Regional Reliability Standards Working Group

Southwest Power Pool Offices
415 North McKinley, #140 Plaza West
Little Rock, AR 72205
☎ (501) 614-3200

May 22, 2007 — 1 to 5 p.m. Central Time
May 23, 2007 — 8 a.m. to 3 p.m. Central Time

Agenda

1. Administrative Items

a) Introductions/Attendance

David Taylor will lead the welcome of the Regional Reliability Standards Working Group (RRSWG) members and guests (see NERC RRSWG Roster - **Attachment 1a**).

Patrick Huntley — SERC Reliability Corporation
Robert (Bob) Millard — Reliability *First* Corporation
Steven Myers — Electric Reliability Council of Texas, Inc.
Farzaneh Tafreshi — Electric Reliability Council of Texas, Inc.
Mak Nagle — Southwest Power Pool
John E. Odom — Florida Reliability Coordinating Council
Kenneth Wilson — Western Electricity Coordinating Council
Guy V. Zito — Northeast Power Coordinating Council, Inc.
Larry Brusseau — Midwest Reliability Organization
David Taylor — North American Electric Reliability Corporation

b) Antitrust Compliance Guidelines

David Taylor will review the NERC Antitrust Compliance Guidelines provided in **Attachment 1b**. It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition. It is the responsibility of every NERC participant and

employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

c) Meeting Notes

The group will select a "volunteer" to take the notes for the meeting.

2) Review of Action Items from Last Meeting

David Taylor will review the action item list developed at the March 19–20, 2007 RRSWG meeting:

| Action Items | Status: | Assigned To: |
|---|---|--------------------------|
| <ul style="list-style-type: none"> Discuss the regions' UFLS programs at the UFLS standards drafting team meeting. | Overviews of each region's UFLS program are to be provided at the initial meeting of the standard drafting team for Project 2007-01 Remains Open | RRSWG |
| <ul style="list-style-type: none"> NERC Regional Reliability Standards Evaluation Procedure - Dave is to correct bullet number 1 under step 2 to match the form. | At their March 13, 2007 meeting the Standards Committee voted for no involvement in regional standards development process. So the NERC Regional Reliability Standards Evaluation Procedure will be updated to correct bullet number 1 under step 2 to match the form at the end of the document. Also, Dave Taylor will change rules for urgent action such that a standard developed under an urgent action will remain a standard and will not expire after 1 year. During the April 30 conference call Dave asked the group to review the procedure again and provide him with any additional comments by May 4. Remains Open | David Taylor |
| <ul style="list-style-type: none"> Taylor is to post the latest version of the NERC Regional Reliability Standards Evaluation Procedure on the Regional Standards portion of the NERC website. | Remains to be done. Remains Open | David Taylor |
| <ul style="list-style-type: none"> David Taylor is to update Appendix A of the NERC Regional Reliability Standards Evaluation Procedure to add more detail to the justification section of the submittal form for a request for a regional standard. | Will be completed when the procedure is updated. Remains Open | David Taylor |
| <ul style="list-style-type: none"> All to discuss ways for creating more uniform standards across all the regions. For example, assigning regional coordinators to standard | To be completed at the next face-to-face meeting currently scheduled in Little Rock, AK on May 22-23. Remains Open | All members of the RRSWG |

| Action Items | Status: | Assigned To: |
|---|---|---------------------------------|
| <p>drafting teams, NERC identification of expectations for submittal of regional standard requests, increased level of detail needed for “procedures”, what is available for “tool boxes”, etc.</p> | | |
| <ul style="list-style-type: none"> Ken Wilson is to provide David Taylor with revisions to the WECC portion of the Regional Standards Under-development page. | <p>Ken is working on this.</p> <p>Remains Open</p> | <p>Ken Wilson</p> |
| <ul style="list-style-type: none"> David Taylor to issue letter to each region requesting a catalog listing of all regional reliability criteria and further requesting each region notify NERC of changes to the listing. | <p>Dave will issue the letter. In the mean time the RRSWG are requested to collect this information and be prepared to discuss this issue at the RRSWG meeting scheduled in Little Rock May 22-23.</p> <p>Remains Open</p> | <p>David Taylor</p> |
| <ul style="list-style-type: none"> Each region to provide a catalog listing of regional reliability criteria. | <p>Remains Open</p> | <p>All members of the RRSWG</p> |
| <ul style="list-style-type: none"> David Taylor to develop a rotation for assigning review of all posted standards and SARs for “fill-in-the-blank” characteristics and regional impacts. | <p>The group decided to review only draft standards and not SARs. Dave will still develop a rotation.</p> <p>Remains Open</p> | <p>David Taylor</p> |
| <ul style="list-style-type: none"> Dave to update the scope of the RRSWG on the RRSWG portion of the NERC website. | <p>New</p> | <p>David Taylor</p> |
| <ul style="list-style-type: none"> David Taylor to WECC ATEC standard to the WECC section of the Regional Reliability Standards Under Development. | <p>New</p> | <p>David Taylor</p> |
| <ul style="list-style-type: none"> David Taylor to provide the group with the latest definition of Mitigation Time Horizon for inclusion into the standard template for each of the regional standards development procedures. | <p>New</p> | <p>David Taylor</p> |

NERC Regional Reliability Standard Evaluation Procedure

David Taylor will review recent updates to the NERC Regional Reliability Standards Evaluation Procedure (**Attachment 3**) and seek endorsement of the procedure by the RRSWG.

3) NERC Regional Reliability Standards Web Page

David Taylor will review recent updates of NERC's regional reliability Web page. Each region will be asked if the information posted for its region on the Regional Standards Under Development page is up to date.

4) Regional Standard versus Regional Criteria

Each region will present its catalog listing of regional reliability criteria to the group per the action item created at the March 19–20 RRSWG meeting.

5) Creating Uniform Regional Standards

David Taylor will discuss ways to improve the development of uniform standards across the regions. Included will be a discussion of potential tools and “tool box” for use by regional standards drafting teams. The group will create a list of action items for developing the tools needed by the regions in developing their regional standards.

6) RRSWG Review of Recent SAR and Standard Postings

The group will discuss any posted standards for “fill-in-the-blank” characteristics and regional impacts. Plus, David Taylor will present a rotation for assigning future review of all posted standards for “fill-in-the-blank” characteristics and regional impacts (see **Attachment 7**).

- a) Transmission Loading Relief IRO-006 — Since the rotation for assigning review of posted SARs and standards has not been discussed, the entire group is asked to review the Transmission Loading Relief IRO-006 standard (**Attachments 7a1 thru 7a4**).

7) Regional Delegation Agreements – Appendix C

The group will discuss the actions being taken by each region to comply with FERC's March 15 Order regarding the regional delegation agreements, specifically with respect to Appendix C, the Regional Standards Development Procedures.

8) Review of Action Items

David Taylor will review the list of outstanding action items and action items generated during the meeting and confirm assignments.

9) Next Steps

The group will discuss and identify the next steps and establish future meeting dates and locations.

Next meetings:

- June 29, 2007
10 a.m.–1 p.m. Eastern Time
WebEx and conference call
- August 1–2 — WECC offices (Salt Lake City, Utah)
1–5 p.m. Mountain Time on August 1
8 a.m.–3 p.m. Mountain Time on August 2
- September 4, 2007
1–5 p.m. Eastern Time
WebEx and conference call
- October 2–3, 2007 — FRCC offices (Tampa, Florida)
1–5 p.m. Eastern Time on October 2
8 a.m.–3 p.m. Eastern Time on October 3

Regional Reliability Standards Working Group Attachment 1a

| | | | |
|-------------------|---|--|---|
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| FRCC | John E. Odom, Jr. Manager of System Planning | Florida Reliability Coordinating Council 1408 N. Westshore Blvd. Suite 1002 Tampa, Florida 33607 | (813) 289-5644 (813) 289-5646 Fx jodom@frcc.com |
| MRO | Larry Brusseau Standards Manager | Midwest Reliability Organization 2774 Cleveland Avenue North Roseville, Minnesota 55113 | (651) 855-1735 (651) 855-1712 Fx le.brusseau@midwestreliability.org |
| NPCC | Guy V Zito Assistant Vice President of Standards | Northeast Power Coordinating Council, Inc. 1515 Broadway 43rd Floor New York, New York 10036 | (212) 840-1070 (212) 302-2782 Fx gzito@npcc.org |
| RFC | Robert W. Millard Director of Standards | ReliabilityFirst Corporation 220 Market Avenue South Canton, Ohio 44702 | (330) 697-4032 Fx bob.millard@rfirst.org |
| SERC | Patrick Huntley EC Staff Engineer | SERC Reliability Corporation 600 North 18th Street P.O. Box 2641 Birmingham, Alabama 35291 | (704) 752-9816 phuntley@serc1.org |
| SPP | Mak Nagle Manager, Transmission Engineering & Modeling | Southwest Power Pool 415 North McKinley Suite 140 Little Rock, Arkansas 72205-3020 | (501) 614-3564 (501) 666-0376 Fx mnagle@spp.org |
| WECC | Kenneth J. Wilson Staff Engineer | Western Electricity Coordinating Council 615 Arapeen Drive Suite 210 Salt Lake City, Utah 84108 | (801) 582-0353 (801) 582-3918 Fx ken@wecc.biz |
| NERC Staff | David Taylor Manager of Regional Standards | North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, New Jersey 08540-5721 | (609) 452-8060 (609) 452-9550 Fx david.taylor@nerc.net |



NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

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

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. PROHIBITED ACTIVITIES

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

Approved by NERC Board of Trustees, June 14, 2002
Technical revisions, May 13, 2005

III. ACTIVITIES THAT ARE PERMITTED

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation and Bylaws are followed in conducting NERC business. Other NERC procedures that may be applicable to a particular NERC activity include the following:

- Reliability Standards Process Manual
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.



Regional Reliability Standards Evaluation Procedure

Draft 12, Version 0.0

May 10, 2007

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Deleted: January 7, 2007

Version 0.0 of the Regional Reliability Standards Evaluation Procedure is the initial draft of the procedure for evaluating regional reliability standards which have been submitted to the North American Electric Reliability Corporation (NERC) for approval, revision, or withdrawal by a regional entity.

DRAFT

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Introduction

Purpose

This procedure outlines the process for NERC's evaluation of regional reliability standards that have been vetted through a North American Electric Reliability Corporation (NERC) approved regional reliability standards development procedure and submitted to NERC by a regional entity for approval.

Proposed regional reliability standards shall be subject to review by NERC, as the electric reliability organization, and approval by FERC in the United States and applicable authorities in Canada and Mexico before becoming mandatory and enforceable. No regional reliability standard shall be effective unless filed by NERC with FERC and applicable authorities in Canada and Mexico and approved by FERC and applicable authorities in Canada and Mexico.

Regional reliability standards, when approved by FERC and applicable authorities in Canada and Mexico, shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the applicable regional entity's region, regardless of membership in the region.

Regional reliability standards shall provide for as much uniformity as possible relative to NERC reliability standards across the interconnected bulk power systems of the North American continent. A regional reliability standard shall be more stringent than a continent-wide reliability standard, shall cover matters not covered by a continent-wide reliability standard, or shall be necessitated by a physical difference in the bulk power system.

Background

NERC is a nonprofit corporation. NERC was certified by the Federal Energy Regulatory Commission (FERC) as the electric reliability organization (ERO) on July 20, 2006. NERC's predecessor organization, the North American Electric Reliability Council, was formed in 1968 as a result of the Northeast blackout in 1965 to promote the reliability of the bulk power systems of North America. NERC works with all stakeholder segments of the electric industry, including regional entities, to develop standards for the reliable planning and operation of the bulk power 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.

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.

Individuals and committees that are responsible for the regional reliability standards development procedure for each of the regional entities shall consider these reliability and market interface 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 power systems. Each regional 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 power systems. Each regional 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 power system reliability and electricity markets are inseparable and mutually interdependent, all regional 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 own, operate, plan, and use the bulk power systems of North America. The obligations or requirements must be material to reliability and measurable. A reliability standard is defined as follows:

“Reliability standard” means a requirement to provide for reliable operation of the bulk-power system, including without limiting the foregoing, requirements for the operation of existing bulk-power system facilities, including cyber security protection, and including the design of planned additions or modifications to such facilities to the extent necessary for reliable operation of the bulk-power system; but shall not include any requirement to enlarge bulk-power system facilities or to construct new transmission capacity or generation capacity¹.

A regional entity may develop, through its own NERC-approved regional reliability standard development procedure, regional reliability standards that go beyond, add detail to, or implement NERC reliability standards, or that cover matters not addressed in NERC reliability standards.

Characteristics and Elements of a Regional Reliability Standard

To ensure as much uniformity as possible between regional and continent-wide reliability standards across the interconnected bulk power system of the North American continent, the characteristics and elements of regional reliability standards must be consistent with the characteristics and elements of continent-wide reliability standards as described in NERC's Reliability Standards Development Procedure.

¹ § 39.1 Code of Federal Regulations.

Roles in the Evaluation of Regional Reliability Standards

Approval, Revision, or Withdrawal of a Regional Reliability Standard

Only regional entities shall be permitted to submit a regional reliability standard to NERC for approval, revision, or withdrawal. A regional entity may submit a regional reliability standard at any time during the regional entity's regional reliability standard development process at the discretion of the individuals or committees responsible for the region's reliability standards process. However, NERC shall publicly notice and post for comment the proposed regional reliability standard no sooner than similar steps related to posting for public comment of the proposed regional standard in the regional entity's standards development process (i.e., no sooner than what the region anticipates is their own 'anticipated final comment period').

Roles in the Evaluation of a Regional Reliability Standard

Board of Trustees — The NERC Board of Trustees shall consider for adoption as reliability standards the regional reliability standards that have been approved by the applicable regional entity's Board of Directors. Once the NERC Board of Trustees adopts a regional reliability standard as a reliability standard, NERC will file the standard with the applicable regulatory authorities to propose the standard be made mandatory and enforceable.

Committees, Subcommittees, Working Groups, and Task Forces — The committees, subcommittees, working groups, and task forces within NERC shall advise NERC as to the technical aspects of a proposed regional reliability standard. (Note: The regional entity requesting action on a specific regional reliability standard shall be permitted to present to the applicable NERC groups the technical aspects of the regional standard and the justification for the regional entity's request for such action.)

Manager of Regional Standards — The NERC regional reliability standards evaluation process shall be administered by NERC's manager of regional standards. The manager of regional standards is responsible for ensuring that the development and revision of regional reliability standards is in accordance with the NERC's Electric Reliability Organization Rules of Procedure, Section 300. The manager of regional standards works to ensure the integrity of the process and completeness of the regional reliability standards. The manager of regional standards facilitates all steps in NERC's review and approval of proposed regional reliability standards.

NERC and Regional Entity Members — The members of NERC and the regional entities may initiate new or revised regional reliability standards and may comment on proposed standards as delineated in the respective regional reliability standards development procedures.

Regional Entity — A regional entity is responsible for submitting a proposed regional reliability standard to NERC for approval, revision, or withdrawal. The regional entity is responsible for responding to comments and deciding when a proposed regional reliability standard is forwarded to the NERC Board of Trustees for adoption.

Regional Entity Standard Drafting Team — A team of technical experts, appointed by the regional entity, that:

- develops the details of the regional reliability standard,
- considers and responds to comments, and

- participates in industry forums to help build consensus on posted draft regional reliability standards.

Regional Reliability Standards Evaluation Procedure

Overview

This regional reliability standards evaluation procedure is dictated by NERC's Electric Reliability Organization Rules of Procedure, Section 300.

Note: The term “days” below refers to calendar days.

Step 1 — Request a Regional Reliability Standard be Approved, Revised, or Withdrawn

Objective: A complete request is submitted to NERC by a regional entity to approve, revise, or withdraw a regional reliability standard that:

1. clearly justifies the purpose and describes the scope and implementation plan of the proposed regional reliability standard, and
2. conforms to the requirements of a NERC-approved regional entity regional reliability standards development procedure.

Sequence Considerations: Submitting a request to approve, revise, or withdraw a regional reliability standard is the first step in the process for NERC evaluation of a regional reliability standard. A regional entity may submit a request to NERC to approve, revise, or withdraw a regional reliability standard at any time in the regional entity's standard development process. However, the NERC public notice and posting for comment of a regional reliability standard (Step 2 below) can begin no sooner than (but can be concurrent with) similar steps related to posting for public comment of the proposed regional standard in the regional entity's regional reliability standards development procedure.

Discussion: Only regional entities may submit to NERC a request to approve, revise, or withdraw a regional reliability standard. Requests by a regional entity to approve, revise, or withdraw a regional reliability standard shall be submitted to NERC's manager of regional standards and the manager of regional standards will electronically acknowledge receipt of the request to the person that submitted the request. Such requests shall be submitted electronically to:

North American Electric Reliability Corporation
Attn: Manager of Regional Standards
E-mail: RegionalStandards@nerc.net

The request shall be submitted using the NERC Regional Reliability Standard Submittal Request form (see Appendix A for sample submittal form) and shall include all of the following:

1. A concise statement of the basis and purpose (scope) of the standard, of the revision of the standard, or of the withdrawal of the standard, whichever is applicable.
2. A concise statement of the justification of the regional reliability standard.
3. The text of the regional reliability standard in MS Word format that:
 - a. has either been, or is anticipated to be, approved by the regional entity's board, and
 - b. is in a format consistent with the NERC template for reliability standards.
4. An implementation plan.
5. The regional entity standard drafting team roster.
6. The names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard.

7. The final ballot results, including a list of significant minority issues that were not resolved.
8. For each public comment period, a copy of each comment submitted and its associated response along with the associated changes made to the standard.

The justification for a regional reliability standard should identify how the proposed regional reliability standard is:

1. a regional reliability standard that is more stringent than the continent-wide reliability standard, including a regional reliability standard that addresses matters that the continent-wide reliability standard does not; or
2. a regional reliability standard that is necessitated by a physical difference in the bulk power system.

The implementation plan shall describe when the standard will become effective. If the implementation is to be phased, the plan shall describe which elements of the standard are to be applied to each class of responsible entities, and when. The plan shall describe any deployment considerations unique to the standard, such as computer applications, measurement devices, databases, or training, as well as any other special steps necessary to prepare for and initially implement the standard.

The implementation plan shall also describe any already approved standards that need to be modified or retired as a result of the proposed standard. The plan must indicate the timing of such modifications or retirements of standards, as related to the effective dates of the new standards.

As noted in the Sequence Considerations above, a regional entity may submit a request for approval, revision, or withdrawal of a regional reliability standard prior to the completion of the public comment period and balloting of the standard phases of the corresponding regional standards development process. In that event, items 7 and 8 listed above must be submitted before step 3 below will be considered complete.

NERC will review the standard for completeness (see Appendix B for sample review checklist) and will inform the regional entity if the request is accepted as complete or requires additional information. This review shall occur within a 30-day period of the submittal of the proposed standard. Once NERC has completed this review and the request has been determined to be complete the proposed standard will be posted for public comment (Step 2).

Step 2 — Solicit Public Comments on Draft Regional Reliability Standard

Objective: Receive stakeholder inputs on the proposed regional reliability standard for the purpose of assessing the following:

1. ~~Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?~~
2. Does the proposed standard pose a significant adverse impact on reliability or commerce of the interconnection and neighboring regions?
3. Does the proposed standard fail to provide a level of reliability of the bulk power system such that the regional reliability standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security?
4. Does the proposed standard create a serious and substantial burden on competitive markets within the interconnection and neighboring regions that is not necessary for reliability?
5. Is the proposed standard more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or is a regional difference necessitated by a physical difference in the bulk power system?

Deleted: Was the proposed standard developed in a fair and open process

Sequence Considerations: *This step is performed at the completion of Step 1 but can begin no sooner than similar steps in the regional entity's regional standards development procedure and may be performed concurrent with similar steps in the regional entity's regional standard development process.*

Discussion: Once NERC has verified that the regional entity has submitted a complete request for approval, revision, or withdrawal of a regional reliability standard, NERC will set the posting start and end dates for the purpose of soliciting public comments. The posting of the proposed regional reliability standard will be linked to the regional entity's standards development documentation for reference and will include the regional entity's complete request including the implementation plan and the justification for the regional standard. Comments will be accepted online using an internet-based application along with other electronic means as necessary. Comments on the proposed regional reliability standard will be accepted for at least one 45-day period from the notice of posting.

Since the need for the regional reliability standard was established at the regional level, comments at this stage in the evaluation of a regional reliability standard will be permitted only on whether the proposed regional reliability standard meets the criteria listed above (see Appendix C for sample comment form). The comments may include recommendations to accept or reject the standard and reasons for that recommendation.

Step 3 — Analysis of the Comments

Objective: *Evaluate stakeholder comments to determine if the proposed regional reliability standard requires additional work.*

Sequence Considerations: *This step is performed following Step 2 and must precede Step 5.*

Discussion: NERC will assemble the comments on the proposed regional reliability standard and supply the assembled comments to the regional entity. NERC will provide the assembled comments to the regional entity within ten days of the end of the public comment period.

The regional entity shall give prompt consideration to the assembled comments in an effort to resolve all expressed objections. The regional entity shall provide NERC reply comments responding to every comment contained in the assembled comments and identify any refinements made to the proposed regional reliability standard as a result of the comments received. The regional entity will summarize comments that were rejected by the regional entity and identify the reason(s) that the comments were rejected, in part or whole. The regional entity will supply the reply comments to the NERC electronically within thirty days of receiving the assembled comments. The regional entity's reply comments will be posted on NERC's website within 14 days of receipt by NERC.

Based on comments received, the regional entity may determine there is an opportunity to improve the standard. In this case, the regional entity may either withdraw the request entirely or revise the proposed standard and request another posting. Although there is no predetermined limit on the number of times a proposed regional reliability standard may be revised and posted, the regional entity should ensure the potential benefits of another posting outweigh the burden on the regional entity and stakeholders.

Step 4 — NERC Evaluation of Proposed Regional Reliability Standard

Objective: *Evaluate whether a proposed regional reliability standard was developed in accordance with all applicable procedural requirements and is compatible with existing standards.*

Sequence Considerations: NERC evaluation of a proposed regional reliability standard shall commence concurrent with Step 2 of this procedure.

Discussion: NERC shall evaluate whether a proposed regional reliability standard has been developed in accordance with all applicable procedural requirements and whether the regional entity has considered and attempted to resolve all stakeholder objections. NERC staff may ask one of the NERC committees, subcommittees, working groups, or task forces to comment as to the technical aspects of the submitted request during this step of the process. The timing of this evaluation will depend on workload, but in no case shall a properly submitted request wait for NERC evaluation more than 45 days from the date of completion of Step 3 above.

Once NERC staff has completed their evaluation and received comments from the applicable NERC committees, subcommittees, working groups, and task forces, NERC will document the evaluation, recommendation, and actions in a report for use in Step 5 of this procedure. NERC shall also post this report for public viewing and provide an electronic copy of the report to the regional entity.

Step 5 — Adoption of the Reliability Standard by the Board

Objective: To have the Board of Trustees adopt the regional reliability standard as a NERC standard, and adopt the associated implementation plan.

Sequence Considerations: This step can only be performed once all prior steps in this procedure have been completed. Typically, standards must be presented to the Board of Trustees for action 30 days before the requested action can be taken.

Discussion: At the conclusion of Step 4 of this procedure, the regional entity having been notified of the results of the NERC staff evaluation and recommendations concerning the proposed regional reliability standard request shall have the option to present the proposed regional reliability standard, along with any objections received, to the NERC Board of Trustees for adoption as part of the body of NERC reliability standards. At a regular or special meeting, the Board of Trustees shall consider adoption of the proposed regional reliability standard. The board shall consider the regional entity's request, NERC staff's recommendation for action on the regional reliability standard, any stakeholder comments, and the regional entity's consideration of comments in determining whether to adopt the regional reliability standard as a NERC reliability standard. The board shall adopt or reject a proposed regional reliability standard, but may not modify a proposed regional reliability standard. If the board chooses not to adopt a regional reliability standard, it shall provide its reasons for not doing so.

Step 6 — Implementation of Regional Reliability Standard

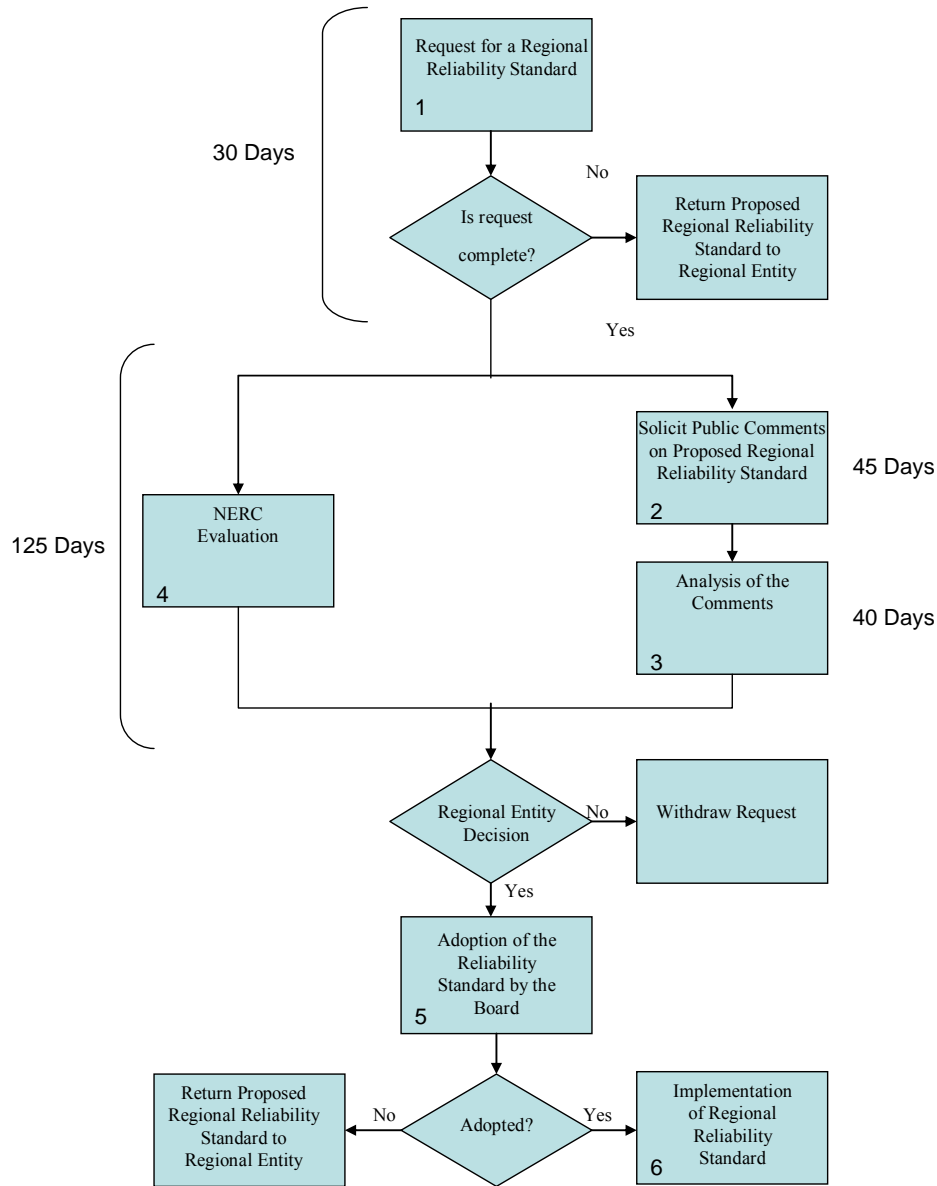
Objective: Industry stakeholders use the regional reliability standard and the compliance group incorporates the standard into its compliance monitoring and enforcement program.

Sequence Considerations: The effective date of a standard will be proposed in the standard implementation plan; however, the actual effective date will be contingent on obtaining the applicable regulatory approvals.

Discussion: Once the Board of Trustees has adopted a regional reliability standard or the revision or retirement of a regional reliability standard, the NERC Board of Trustees will direct the standard to be filed with applicable governmental agencies in the United States, Canada, and Mexico for approval. The regional entity may request to assist NERC in any governmental filing process.

Once a regional reliability standard is approved by applicable governmental agencies, all bulk power system owners, operators, and users within the region are required to comply with the standard in accordance with applicable statutes, regulations and agreements. The NERC staff will notify the regional entities of the regulatory decisions. If accepted for filing the regional reliability standard will be forwarded to the regional/NERC compliance programs within 10 business days for entrance into the ERO's compliance monitoring and enforcement program in accordance with the schedule included in the standard's associated implementation plan.

Process Diagram



Special Procedures

Urgent Actions

Under certain conditions, the regional entity may designate a proposed regional reliability standard or revision to a regional reliability standard as requiring urgent action. Urgent action may be appropriate when a delay in implementing a proposed regional reliability standard or revision can materially impact reliability of the bulk power systems. The regional entity 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 regional entity submits a request for approval, revision, or withdrawal of a regional reliability standard to NERC's manager of regional standards at RegionalStandards@nerc.net. The request must include a justification for urgent action. If the regional entity designates the request as an urgent action item, then NERC posts the request for public comment (Step 2). This posting requires a minimum 30-day posting period instead of the standard 45 days. NERC and the regional entity will do everything in their power to expedite the process and will attempt to complete Steps 1 through 4 of the NERC regional reliability standards evaluation process in 60 days or less.

Appeals

Individuals 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 NERC's evaluation process of a regional reliability standard shall have the right to appeal to NERC. This appeals process applies only to the NERC regional reliability standards evaluation process as defined in this procedure.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within 30 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 NERC a complaint in writing that describes the substantive or procedural action or inaction associated with the evaluation process for a regional reliability standard. The appellant describes in the complaint the actual or potential adverse impact to the appellant. Assisted by any necessary staff and committee resources, NERC 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

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Any regional reliability 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 regional reliability standard permanent, then the standard would be required to go through the full process or comply with requirements in the paragraph below. ¶ Urgent actions that expire may be renewed using the urgent action process again, in the event a permanent standard is not adopted. 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 adoption by the Board of Trustees, and approval by any applicable governmental authorities.

If after the Level 1 Appeal the appellant remains unsatisfied with the resolution, as indicated by the appellant in writing to NERC, NERC 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.

NERC 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 regional entity 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 regional reliability standard, as these responsibilities remain with the Board of Trustees. 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 posting of the recommendation on the reliability standard in question identified in Step 4 of this procedure.

Maintenance of Regional Reliability Standards Evaluation Procedure

Requests to Revise the Regional Reliability Standards Evaluation Procedure

Any person or entity may submit a written request to modify the Regional Reliability Standards Evaluation Procedure. NERC shall oversee the handling of the request. NERC shall prioritize all requests, merge related requests, and respond to each requestor within 90 days.

On-line Standards Information System

NERC shall be responsible for maintaining an electronic database of information regarding currently proposed and currently in effect regional reliability standards. This information shall include current regional reliability standards in effect, proposed revisions to regional reliability standards, and proposed new regional reliability standards. This information shall provide a record, for at a minimum the previous five years, of the review and approval process for each regional reliability standard, including public comments received and the associated responses during the approval process. This information shall be available through public internet access.

Archived Standards Information

NERC shall be responsible for maintaining a historical record of regional reliability standards information that is no longer maintained on-line. For example, regional reliability standards that expired or were replaced may be removed from the on-line system. 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 regional reliability standards information shall be available electronically within 30 days following the receipt by NERC of a request from a regional entity.

Appendix A



Regional Reliability Standard Submittal Request

Region:

Regional Standard Number:

Regional Standard Title:

Date Submitted:

Regional Contact Name:

Regional Contact Title:

Regional Contact Telephone Number:

Request (check all that apply):

- Approval of a new standard
- Revision of an existing standard
- Withdrawal of an existing standard
- Urgent Action

Has this action been approved by your Board of Directors (if no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

- Yes
- No

[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]

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Concise statement of the basis and purpose (scope) of request:

Concise statement of the justification of the request:

Other – please attach or include as separate files:

- **The text of the regional reliability standard in MS Word format that:**
 - **has either been, or is anticipated to be, approved by the regional entity's board, and**
 - **is in a format consistent with the NERC template for reliability standards.**
- **An implementation plan.**
- **The regional entity standard drafting team roster.**
- **The names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard.**
- **The final ballot results, including a list of significant minority issues that were not resolved, and**
- **For each public comment period, a copy of each comment submitted and its associated response along with the associated changes made to the standard.**

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Appendix B



**Regional Reliability Standard
Submittal Review Checklist**

Region:

Regional Standard Number:

Regional Standard Title:

Date Standard Received:

Date Region Notified of Receipt:

Date Standard Reviewed:

Submittal Review Status:

Complete

Incomplete

Reviewed by:

Approved by:

Review of Request for Completeness:

1. Was a concise statement of the basis and purpose (scope) of request supplied?
 Yes
 No
2. Was a concise statement of the justification of the request supplied?
 Yes
 No
3. Was the text of the regional reliability standard supplied in MS Word format?
 Yes
 No
4. Was an implementation plan supplied?
 Yes
 No
5. Was the regional entity standard drafting team roster supplied?
 Yes
 No
6. Were the names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard supplied?
 Yes
 No
7. Were the final ballot results, including a list of significant minority issues that were not resolved, supplied?
 Yes
 No
8. For each public comment period, was a copy of each comment submitted and its associated response along with the associated changes made to the standard supplied?
 Yes
 No

Review of Standard for Completeness:**Title**

9. Is there a title that provides a brief, descriptive phrase identifying the topic of the standard?

Yes

No

Number

10. Does the standard have a unique identification number not already used by any NERC reliability standard?

Yes

No

Purpose

11. Does the purpose explicitly state what reliability-related outcome will be achieved by the adoption of the standard?

Yes

No

Applicability

12. Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted?

Yes

No

13. Does this reliability standard identify the geographic applicability of the standard, such as the entire interconnection, or within a regional entity area?

Yes

No

14. Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria?

Yes

No

Effective Date

15. Does the effective date start on the 1st day of the 1st quarter after entities are expected to be compliant?
- Yes
 No
16. Does the effective date provide time to file with applicable regulatory authorities and provide notice to responsible entities of the obligation to comply?
- Yes
 No

Requirements

17. Does each requirement identify the functional entity that is responsible and the action to be performed or the outcome to be achieved?
- Yes
 No
18. Does this reliability standard 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 practices and the public interest?
- Yes
 No
19. Are the requirements free of additional comments or statements for which compliance is not mandatory, such as background or explanatory information?
- Yes
 No

Violation Risk Factors

20. Is there a Violation Risk Factor (High, Medium, Lower) for each requirement?
- Yes
 No

Mitigation Time Horizons

21. Is there a Mitigation Time Horizon (Long-term Planning; Operations Planning; Same-day Operations; Real-time Operations; Operations Assessment) for each requirement?
- Yes
 No

Measures

22. Does each measure identify to whom the measure applies and the expected level of performance or outcomes required to demonstrate compliance?

Yes

No

23. Is each measure tangible, practical, and as objective as is practical?

Yes

No

24. Does each measure clearly refer to the requirement(s) to which it applies?

Yes

No

25. Is there a measure for each requirement?

Yes

No

Compliance Monitoring Responsibility

26. Is the 'Electric Reliability Organization' identified as the Compliance Monitor?

Yes

No

Compliance Monitoring Period

27. Does the standard identify the time period in which performance or outcomes is measured, evaluated, and then reset?

Yes

No

Data Retention

28. Does the standard identify the data retention requirements and assignment of responsibility for data archiving?

Yes

No

Additional Compliance Information

29. Does the standard identify the process that will be used to evaluate data or information for the purpose of assessing performance or outcomes?

Yes

No

30. Does the standard identify the specific data or information that is required to measure performance or outcomes?

Yes

No

31. Does the standard identify the entity that is responsible for providing data or information for measuring performance or outcomes?

Yes

No

Violation Severity Levels

32. Is there a Violation Severity Level (lower, moderate, high, severe) for violation of each of the requirements?

Yes

No

Associated Documents

33. If there are standards or forms that are referenced within a standard, are the full names and numbers of the standard identified under, 'Associated Documents'.

Yes

No

Definitions

34. Are the definitions used and provided in the standard consistent with the NERC definitions.

Yes

No

Other Observations:

35. Are there any additional comments?

Yes

No

Appendix C

Please use this form to submit comments on the [Regional Entity]'s regional reliability standard [Regional Standard Number and Title]. Comments must be submitted by **[Date]**. You may submit the completed form by e-mail to regionalstandardscom@nerc.com with the words "**[Regional Entity] [Regional Standard Number and Title]**" in the subject line. If you have questions please contact **David Taylor** at David.Taylor@nerc.net or by telephone at 609-452-8060.

| Individual Commenter Information | | |
|--|--------------------------|--|
| (Complete this page for comments from one organization or individual.) | | |
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| NERC Region | | Registered Ballot Body Segment |
| <input type="checkbox"/> ERCOT | <input type="checkbox"/> | 1 — Transmission Owners |
| <input type="checkbox"/> FRCC | <input type="checkbox"/> | 2 — RTOs and ISOs |
| <input type="checkbox"/> MRO | <input type="checkbox"/> | 3 — Load-serving Entities |
| <input type="checkbox"/> NPCC | <input type="checkbox"/> | 4 — Transmission-dependent Utilities |
| <input type="checkbox"/> RFC | <input type="checkbox"/> | 5 — Electric Generators |
| <input type="checkbox"/> SERC | <input type="checkbox"/> | 6 — Electricity Brokers, Aggregators, and Marketers |
| <input type="checkbox"/> SPP | <input type="checkbox"/> | 7 — Large Electricity End Users |
| <input type="checkbox"/> WECC | <input type="checkbox"/> | 8 — Small Electricity End Users |
| <input type="checkbox"/> NA – Not Applicable | <input type="checkbox"/> | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | <input type="checkbox"/> | 10 — Regional Reliability Organizations and Regional Entities |

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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

A regional reliability standard shall be: (1) a regional reliability standard that is more stringent than the continent-wide reliability standard, including a regional standard that addresses matters that the continent-wide reliability standard does not; or (2) a regional reliability standard that is necessitated by a physical difference in the bulk power system. Regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. Regional reliability standards, when approved by FERC and applicable authorities in Mexico and Canada shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the applicable area, regardless of membership in the region.

The approval process for a regional reliability standard requires NERC to publicly notice and request comment on the proposed standard. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

Unfair or Closed Process — The regional reliability standard was not developed in a fair and open process that provided an opportunity for all interested parties to participate. Although a NERC-approved regional reliability standards development procedure shall be presumed to be fair and open, objections could be raised regarding the implementation of the procedure.

Adverse Reliability or Commercial Impact on Other Interconnections — The regional reliability standard would have a significant adverse impact on reliability or commerce in other interconnections.

Deficient Standard — The regional reliability standard fails to provide a level of reliability of the bulk power system such that the regional reliability standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security.

Adverse Impact on Competitive Markets within the Interconnection — The regional reliability standard would create a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability.

You are not required to answer all questions. Enter all comments in simple text format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?

Yes

No

Comments:

2. Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?

Yes

No

Comments:

3. Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?

Yes

No

Comments:

4. Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

- Yes
- No

Comments:

5. Does the proposed regional reliability standard meet at least one of the following criteria?

- **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

- Yes
- No

Comments:

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SC authorized moving the SAR forward to standard drafting (December 5, 2006).
2. SC appointed the SDT (February 9, 2007).

Proposed Action Plan and Description of Current Draft:

This 45-day posting of IRO-006-4 and its associated implementation plan identifies the split of IRO-006 between NERC and NAESB so that the business practices are moved into a NAESB business practice and the reliability requirements are retained in the revised IRO-006.

Future Development Plan:

| Anticipated Actions | Anticipated Date |
|--|--|
| 1. Post response to comments submitted on initial draft of IRO-006-4 | June 21, 2007 |
| 2. Request Standards Committee to authorize proceeding to ballot. | June 22, 2007 |
| 3. Post for 30-day pre-ballot period. | June 25–July 15, 2007; reduced to 20 days if possible. |
| 4. Conduct first ballot. | July 16–25, 2007 |
| 5. Post response to comments on first ballot | July 26, 2007 |
| 6. Conduct second ballot | Waived if possible |
| 7. Post for 30-day period prior to board adoption. | Waived if possible |
| 8. Board adoption date. | August 1, 2007 |

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** Reliability Coordination — Transmission Loading Relief (TLR)
2. **Number:** IRO-006-4
3. **Purpose:** The purpose of this standard is to provide a method to prevent and or manage congestion on the bulk electric system.
4. **Applicability:**
 - 4.1. Reliability Coordinators.
 - 4.2. Balancing Authorities.
5. **Proposed Effective Date:** First day of first quarter after BOT adoption.

B. Requirements

- R1.** A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, with its authority and at its discretion, select one or more procedures to provide transmission loading relief. These procedures can be a “local” (regional, interregional, or sub-regional) transmission loading relief procedure or one of the following Interconnection-wide procedures: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]
- This requirement simply states; the RC has the authority to act, the RC should know at what limits he/she needs to act, the RC has pre-identified regional, interregional and sub-regional TLR procedures.
- R1.1.** The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection provided in Attachment 1-IRO-006-4. The TLR procedure alone is an inappropriate and ineffective tool to mitigate an IROL violation. Other acceptable and more effective procedures to mitigate actual IROL violations include: reconfiguration, redispatch, or load shedding.
- Comment: see FERC Order 693 paragraph 964 regarding recommendation for using tools other than TLR to mitigate an actual IROL.
- R1.2.** The 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.
- R1.3.** 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/mktrules/protocols/current.html>
- Note: the URL has changed.
- R2.** The Reliability Coordinator shall only use local transmission loading relief or congestion management procedures to which the Transmission Operator experiencing the potential or actual SOL or IROL violation is a party. [*Violation Risk Factor: Low*] [*Time Horizon: Operations Planning*]

- R3.** A Reliability Coordinator may implement a local transmission loading relief or congestion management procedure simultaneously with an Interconnection-wide procedure. However, each 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 obtain prior approval by the ERO. [*Violation Risk Factor: Low*] [*Time Horizon: Operations Planning*]
- R4.** When Interconnection-wide procedures are implemented to curtail Interchange Transactions that cross an Interconnection boundary, each Reliability Coordinator shall comply with the provisions of the Interconnection-wide procedure. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]
- R5.** During the implementation of relief procedures, and up to the point that emergency action is necessary, Reliability Coordinators and Balancing Authorities shall comply with applicable Interchange scheduling standards. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

Comment: R5 will be reviewed during Phase 3 of the TLR drafting team work. See white paper for explanation of the three phases of changes to this standard.

C. Measures

- M1.** Each Reliability Coordinator shall be capable of providing evidence (such as logs) that demonstrate when Eastern Interconnection, WECC, or ERCOT Interconnection-wide transmission loading relief procedures are implemented, the implementation follows the respective established procedure as specified in this standard (R1, R1.1, R1.2 and R1.3).
- M2.** Each Reliability Coordinator shall be capable of providing evidence (such as written documentation) that the Transmission Operator experiencing the potential or existing SOL or IROL violations is a party to the local transmission loading relief or congestion management procedures when these procedures have been implemented (R2).
- M3.** Each Reliability Coordinator shall be capable of providing evidence (such as NERC meeting minutes) that the local procedure has received prior approval by the ERO when such procedure is used as a substitute for curtailment as directed by the Interconnection-wide procedure (R3).
- M4.** Each Reliability Coordinator shall be capable of providing evidence (such as logs) that the responding Reliability Coordinator complied with the provisions of the Interconnection-wide procedure as requested by the initiating Reliability Coordinator when requested to curtail an Interchange Transaction that crosses an Interconnection boundary (R4).
- M5.** Each Reliability Coordinator and Balancing Authority shall be capable of providing evidence (such as Interchange Transaction Tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts) that they have complied with applicable Interchange scheduling standards INT-001, INT-003, and INT-004 during the implementation of relief procedures, up to the point emergency action is necessary (R5).

D. Compliance

1. Compliance Monitoring Process

The Regional Entity shall have responsibility for compliance monitoring.

1.1. Compliance Monitoring Responsibility

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Compliance Monitoring Period: One calendar year.

Reset Period: One month without a violation.

1.3. Data Retention

The Reliability Coordinator shall maintain data for eighteen months for M1, M4, and M5.

The Reliability Coordinator shall maintain data for the duration the Transmission Operator is party to the procedure in effect plus one calendar year thereafter for M2.

The Reliability Coordinator shall maintain data for the approved duration of the procedure in effect plus one calendar year thereafter for M3.

1.4. Additional Compliance Information

Each Reliability Coordinator and Balancing Authority shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually and reporting by exception. The Compliance Monitor may also use scheduled on-site reviews every three years, and investigations upon complaint, to assess performance.

Each Reliability Coordinator and Balancing Authority shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within 5 days of a request as part of an investigation upon complaint:

1.4.1 Operations logs, voice recordings or transcripts of voice recordings or other documentation providing the evidence of its compliance to all the requirements for all Interconnection-wide TLR procedures that it has implemented during the review period.

1.4.2 TLR reports.

2. Violation Severity Levels

2.1. Lower. There shall be a lower violation severity level if any of the following conditions exist:

2.1.1 For each TLR in the Eastern Interconnection, the Reliability Coordinator violates one (1) requirement of the applicable Interconnection-wide procedure (R1)

2.1.2 The Reliability Coordinators or Balancing Authorities did not comply with applicable Interchange scheduling standards during the implementation of the relief procedures, up to the point emergency action is necessary (R5).

2.2. Moderate.

2.2.1 For each TLR in the Eastern Interconnection, the Reliability Coordinator violates two (2) to three (3) requirements of the applicable Interconnection-wide procedure (R1).

2.3. High. There shall be a high violation severity level if any of the following conditions exist:

2.3.1 For each TLR in the Eastern Interconnection, the applicable Reliability Coordinator violates four (4) to five (5) requirements of the applicable Interconnection-wide procedure (R1).

2.3.2 When requested to curtail an Interchange Transaction that crosses an Interconnection boundary utilizing an Interconnection-wide procedure, the responding Reliability Coordinator did not comply with the provisions of the Interconnection-wide procedure as requested by the initiating Reliability Coordinator (R4).

2.4. Severe. There shall be a severe violation severity level if any of the following conditions exist:

2.4.1 For each TLR in the Eastern Interconnection, the Reliability Coordinator violates six (6) or more of the requirements of the applicable Interconnection-wide procedure (R1).

2.4.2 A Reliability Coordinator implemented local transmission loading relief or congestion management procedures to relieve congestion but the Transmission Operator experiencing the congestion was not a party to those procedures (R2).

2.4.3 A Reliability Coordinator implemented local transmission loading relief or congestion management procedures as a substitute for curtailment as directed by the Interconnection-wide procedure but the local procedure had not received prior approval by the ERO (R3).

2.4.4 While attempting to mitigate an existing IROL violation in the Eastern Interconnection, the Reliability Coordinator applied TLR as the sole remedy for an existing IROL violation.

2.4.5 While attempting to mitigate an existing constraint in the Western Interconnection using the “WSCC Unscheduled Flow Mitigation Plan”, the Reliability Coordinator did not follow the procedure correctly.

2.4.6 While attempting to mitigate an existing constraint in ERCOT using Section 7 of the ERCOT Protocols, the Reliability Coordinator did not follow the procedure correctly.

E. Regional Differences

1. [PJM/MISO Enhanced Congestion Management](#) (Curtailment/Reload/Reallocation) Waiver approved March 25, 2004. To be retired upon completion of the field test, and in the interim the Regional Difference will be contained in both the NERC and NAESB standards.

This section on Regional Differences is highlighted for transfer to NAESB following completion of the MISO/PJM/SPP field test as described in the white paper.

2. Southwest Power Pool (SPP) Regional Difference – Enhanced Congestion Management (Curtailment/Reload/Reallocation). The SPP regional difference, which is equivalent to the PJM/MISO waiver, shall apply within the SPP region as follows:

This regional difference impacts actions on behalf of those SPP Balancing Authorities that are participating in the SPP market. This regional difference does not impact those Balancing Authorities for which SPP will continue to act as the Reliability Coordinator but that are not participating in the SPP market.

SPP shall calculate the impacts of SPP market flow on all facilities included in SPP's Coordinated Flowgate List. SPP shall conduct sensitivity studies to determine which external flowgates (outside SPP's footprint) are significantly impacted by the market flows of SPP's control zones (currently the balancing areas that exist today in the IDC). SPP shall perform studies to determine which external flowgates SPP will monitor and help control. An external flowgate selected by one of the studies will be considered a Coordinated Flowgate (CF).

In its calculation, SPP shall consider market flow impacts as the impacts of energy dispatched by the SPP market and self-dispatched energy serving load in the market footprint, but not tagged. SPP shall use a method equivalent to the PJM/MISO Market Flow Calculation methodology identified in the PJM/MISO waiver. Impacts of tagged transactions representing delivery of energy not dispatched by the SPP market and energy dispatched by the market but delivered outside the footprint will not be included in market flow.

SPP shall separate the market flow impacts for current hour and next hour into their appropriate priorities and shall provide those market flow impacts to the IDC. The market flows will be represented in the IDC and made available for curtailment under the appropriate TLR Levels. The market flow impacts will not be represented by conventional interchange transaction tags.

The SPP method will impact the following sections of the TLR Procedure:

Network and Native Load (NNL) Calculations — The SPP regional difference modifies Attachment 1-IRO-006-1 Section 5 “Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service” within the SPP region.

Section 5 of Attachment 1-IRO-006-1 requires 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 balancing authority.

SPP shall use a “Market Flow Calculation” methodology to calculate the portion of parallel flows on all facilities included in the RTO’s “Coordinated Flowgate List” due to NI service or service to NL of each balancing authority.

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 to the “Per Generator Method” method, while providing increased Interchange Distribution Calculator (IDC) granularity. 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.

These NNL values will be provided to the IDC to be included and represented with the calculated NNL values of other Balancing Authorities for the purposes of identifying and obtaining required NNL relief across a flowgate in congestion under a TLR Level 5A/5B.

Pro Rata Curtailment of Non-Firm Market Flow Impacts — The SPP regional difference modifies Attachment 1-IRO-006-1 Appendix B “Transaction Curtailment Formula” within the SPP region.

Appendix B “Transaction Curtailment Formula” details the formula used to apply a weighted impact to each non-firm tagged Interchange Transaction (Priorities 1 thru 6) for the purposes of Curtailment by the IDC. For the purpose of Curtailment, the non-firm market flow impacts (Priorities 2 and 6) submitted to the IDC by SPP should be curtailed pro-rata as is done for Interchange Transaction using firm transmission service. This is because several of the values needed to assign a weighted impact using the process listed in Appendix B 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 are to be curtailed pro rata, the impacting non-firm tagged Interchange Transactions could still use the existing processes to assign the weighted impact value.

Assignment of Sub-Priorities — The SPP regional difference modifies Attachment 1-IRO-006-1 Appendix E “How the IDC Handles Reallocation”, Section E2 “Timing Requirements”, within the SPP region.

Under the header “IDC Calculations and Reporting” in Section E2 of Appendix E to Attachment 1-IRO-006-1, the following requirement exists: “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. |
| 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 | The Transaction would not be allowed to start until all other Interchange Transactions submitted prior to the TLR with the same |

| | | |
|--|---|---|
| | 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.) | 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. |
|--|---|---|

SPP shall use a “Market Flow Calculation” methodology to calculate the amount of energy flowing across all facilities included in the RTO’s “Coordinated Flowgate List” that is associated with the operation of the SPP 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 and provided to the IDC by SPP. 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, for the purposes of reallocation, a sub-priority (S1 thru S4) should be assigned to these market flow impacts by the NERC IDC as follows, using comparable logic as would be used if the impacts were in fact tagged transactions.

| Priority | Purpose | Explanation and Conditions |
|----------|---|--|
| S1 | To allow existing market flow to maintain or reduce its current MW amount. | The currently flowing MW amount is the amount of market flow existing after the RTO has recognized the constraint for which TLR has been called. If the calculated amount is negative, zero is used instead. |
| S2 | To allow market flow that has been curtailed or halted by TLR to reload to its desired amount for the current-hour. | This is the difference between the current hour unconstrained market flow and the current market flow. If the current-hour unconstrained market flow is not available, the IDC will use the most recent market flow since the TLR was first issued or, if not available, the market flow at the time the TLR was first issued. |
| S3 | To allow a market flow to increase to its next-hour desired amount. | This is the difference between the next hour and current hour unconstrained market flow. |

To be retired upon completion of the field test, and in the interim the Regional Difference will be contained in both the NERC and NAESB standards.

F. Associated Documents

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 |
| 3 | February 26, 2007 | Revised Purpose and Attachment 1 related to NERC NAESB split of the TLR procedure | Revision |

Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief – Attachment 1

PLEASE NOTE: items designated for inclusion in the NAESB TLR business practice following completion of the standard revision were deleted. Please see the mapped document to see which items were move to NAESB and what future changes are expected.

Attachment 1-IRO-006

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.

Applicability

This standard only applies to the Eastern Interconnection.

The flexibility for ISOs and RTOs to use redispatch is contained explicitly in the NAESB business practice Section 1.3.

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 SOL and IROL violations.** A Reliability Coordinator may utilize the TLR Procedure to mitigate potential or existing System Operating Limit (SOL) violations or to prevent or mitigate Interconnection Reliability Operating Limit (IROL) violations on any transmission facility modeled in the IDC. However, the TLR procedure is an inappropriate and ineffective tool as a sole means to mitigate existing IROL violations due to the time required to implement the procedure. Reconfiguration, redispatch, and load shedding are more timely and effective in mitigating existing IROL violations
 - 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.
- 1.3. **Sequencing of TLR Levels and taking emergency action.** The Reliability Coordinator shall not be required to follow the TLR Levels in their numerical sequence (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

This notification is automated in the Interchange Distribution Calculator (IDC) and populates a message on the NERC RCIS.

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.

This notification is automated in the Interchange Distribution Calculator (IDC) and populates a message on the NERC RCIS.

1.4.3. Notifying Sink 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.

1.6. 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 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.

1.7 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.

Creation and distribution of the TLR Procedure Log is now automated in the IDC.

1.8 TLR Event Review. The Reliability Coordinator shall report the TLR event to the Operating Reliability Subcommittee in accordance with TLR review processes established by NERC as required.

1.8.1 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.

1.8.2 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.

The Market Committee no longer exists and this requirement will be removed in Phase 3.

- 1.8.3 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.

2.3 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.

2.4. 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.

2.5 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. Reconfiguration procedures. The issuance of a TLR Level 4 shall result in the curtailment, in the current hour and the next hour, of all Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold 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.

2.7. 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.

2.8. Curtailment of Interchange Transactions Using Firm Transmission Service

2.8.1. 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:

2.8.1.1. 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

2.8.1.2. 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.

Formerly NERC section 3.3

2.9. TLR Level 6 — Emergency Procedures

2.9.1 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.

2.9.2 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.

3.0 TLR Level 0 — TLR concluded

3.0.1 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.

Requirements

4.1 The Reliability Coordinator shall be allowed to call a TLR 3b at any time to help mitigate a SOL or IROL violation.

4.2 The Reliability Coordinator shall Reallocate Interchange Transactions using Non-firm Point-to-Point Transmission for the next hour to maintain the desired flow using Reallocation in accordance with the following timing specification:

4.2.1 If issued prior to XX: 25, Non-firm Interchange Transactions will be curtailed to meet the desired current hour relief

4.2.1.1 At XX: 25 a Reallocation will be performed to maintain the desired flow at the top of the following hour

4.2.2 If issued after XX: 25, Non firm Interchange Transactions will be curtailed to meet the desired current hour relief and a Reallocation will be performed to maintain the target flow identified for the current hour.

4.2.3 Transactions must be in the IDC by the Approved-tag Submission Deadline for Reallocation.

4.3 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:

4.3.1 Interchange Transactions using Non-firm Point-to-Point Transmission Service that are to be curtailed or held during current and next hours.

4.3.2 Interchange Transactions using Firm Point-to-Point Transmission Service that were entered after XX:25 or issuance of TLR 3b (see Case 3 in Appendix F).

4.4 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.

- 4.5** The Reliability Coordinator will no longer be required 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 due to the inherent next hour Reallocation that takes place for the top of the next hour in the TLR Level 3b.

Appendices for Transmission Loading Relief Standard

PLEASE NOTE: items designated for inclusion in the NAESB TLR business practice following completion of the standard revision were deleted from this version of the NERC standard. Please see the mapped document to see which requirements were moved to NAESB and what future changes are expected. Appendices B, D, G, and the sub-priority portions of E-2 have been moved to NAESB, The appendices below (A, C, E, F) will be renumbered in the final standard.

Appendix A. Transaction Management and Curtailment Process.

Appendix C. Sample NERC Transmission Loading Relief Procedure Log.

Appendix E. How the IDC Handles Reallocation.

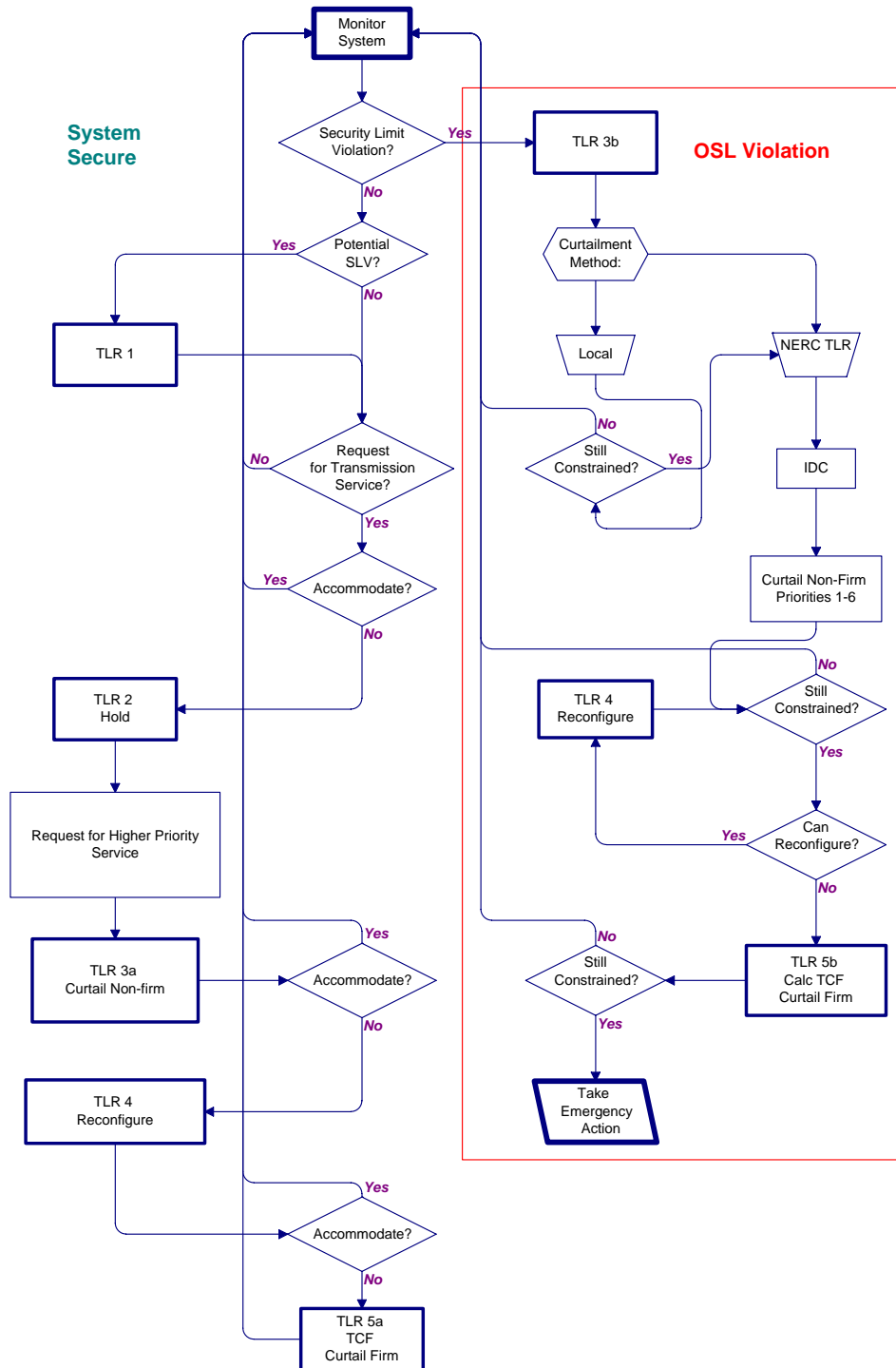
Section E1: Summary of IDC Features that Support Transaction Reloading/Reallocation.

Section E2: Timing Requirements.

Appendix F. Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.

Appendix A. Transaction Management and Curtailment Process

This flowchart depicts an overview of the Transaction Management and Curtailment process. Detailed decisions are not shown.



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:

Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief – Attachment 1

- 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.
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).

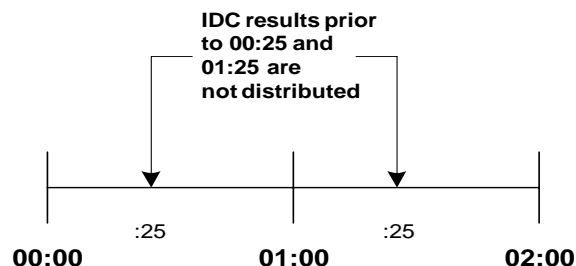


Figure 5 - IDC report may be run prior to 00:25, but results are not distributed.

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

Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief – Attachment 1

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 | $850 \text{ MW} - 800 \text{ MW} = 50 \text{ MW}$ |
| Amount to enter into IDC for Transactions using Point-to-Point Transmission Service | $950 \text{ MW} - 50 \text{ MW} = 900 \text{ MW}$ |

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 | $1000 \text{ MW} - 800 \text{ MW} = 200 \text{ MW}$ |
| Amount to enter into IDC for Transactions using Point-to-Point Transmission Service | $950 \text{ MW} - 200 \text{ MW} = 750 \text{ MW}$ |

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 | $750 \text{ MW} - 800 \text{ MW} = -50 \text{ MW}$ 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

Examples of Interchange Transactions using Non-firm Transmission Service sub-priority settings begin in the **Transaction Sub-priority Examples** following sections

2. 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.

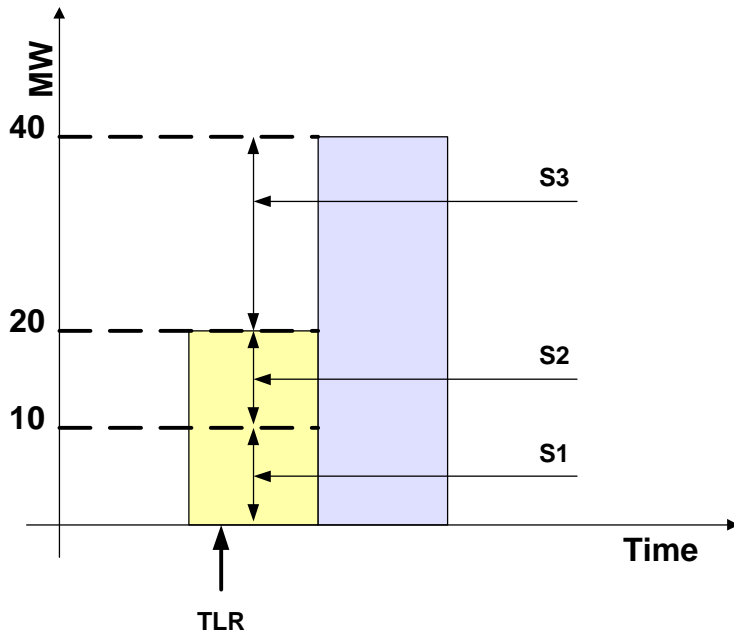
Transaction Sub-Priority Examples

The following describes examples of Interchange Transactions using Non-firm Transmission Service sub-priority setting for an 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.

Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief — Attachment 1

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 |

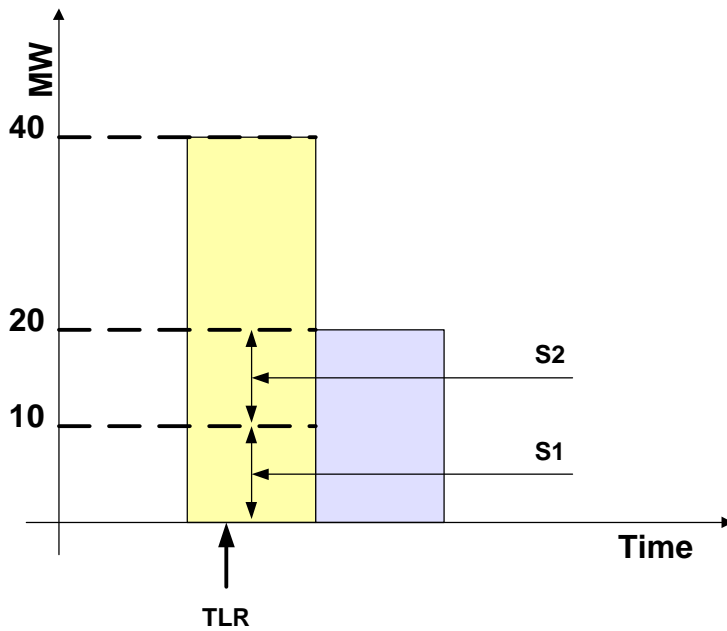


Sub-priorities for Transaction MW:

| <i>Sub-Priority</i> | <i>MW Value</i> | <i>Explanation</i> |
|---------------------|-----------------|---------------------------------------|
| 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 |

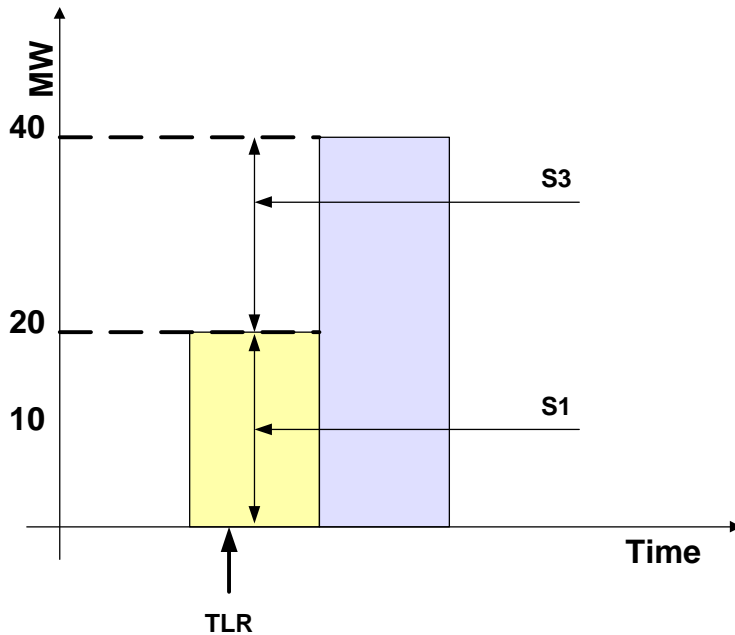


Sub-priorities for Transaction MW:

| <i>Sub-Priority</i> | <i>MW Value</i> | <i>Explanation</i> |
|---------------------|-----------------|---|
| S1 | 10 MW | Maintain current curtailed flow |
| S2 | +10 MW | Reload to <i>lesser</i> 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

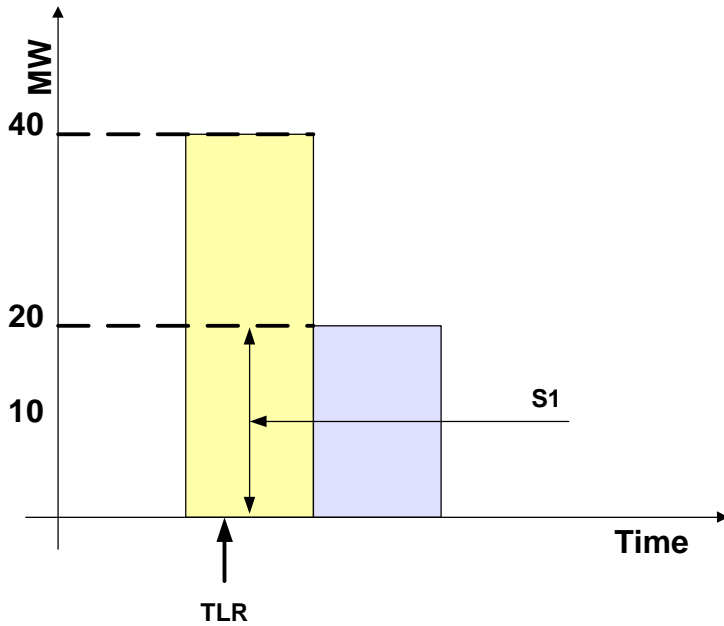
| | |
|---|------------------------|
| Energy Profile: Current hour | 20 MW |
| Actual flow following curtailment: Current hour | 20 MW (no curtailment) |
| Energy Profile: Next hour | 40 MW |



| <i>Sub-Priority</i> | <i>MW Value</i> | <i>Explanation</i> |
|---------------------|-----------------|---|
| S1 | 20 MW | Maintain current flow (not curtailed) |
| S2 | +0 MW | Reload to <i>lesser</i> 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 |

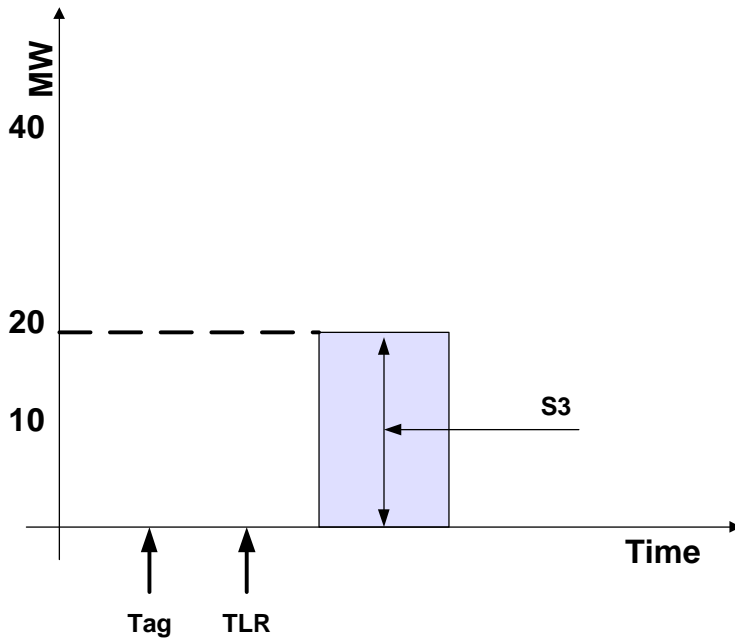


Sub-priorities for Transaction MW:

| <i>Sub-Priority</i> | <i>MW Value</i> | <i>Explanation</i> |
|---------------------|-----------------|---|
| S1 | 20 MW | Reduce flow to next-hour Energy Profile (20MW) |
| S2 | +0 MW | Reload to <i>lesser</i> 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 <i>after</i> TLR initiated) |
| Energy Profile: Next hour | 20 MW |



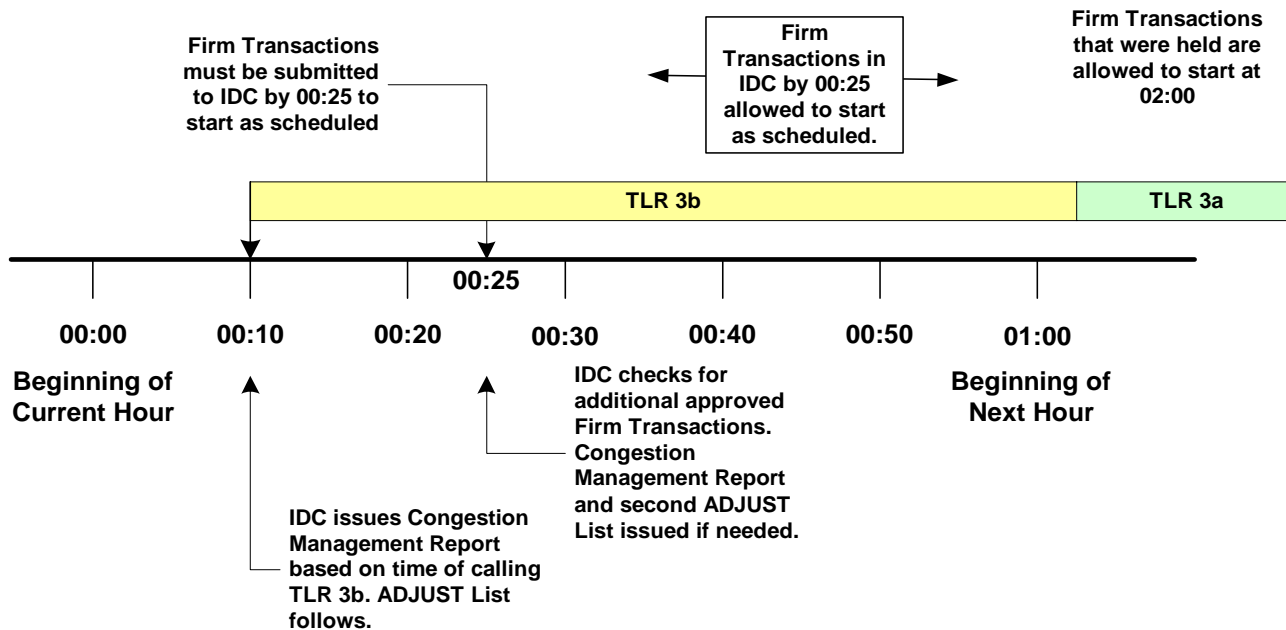
| <i>Sub-Priority</i> | <i>MW Value</i> | <i>Explanation</i> |
|---------------------|-----------------|--------------------------------------|
| S1 | 0 MW | Transaction was not allowed to start |
| S2 | +0 MW | Transaction was not allowed to start |
| S3 | +20 MW | Next-hour Energy Profile is 20MW |
| 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.



The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.

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.

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.

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.

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.

**Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief –
Attachment 1**

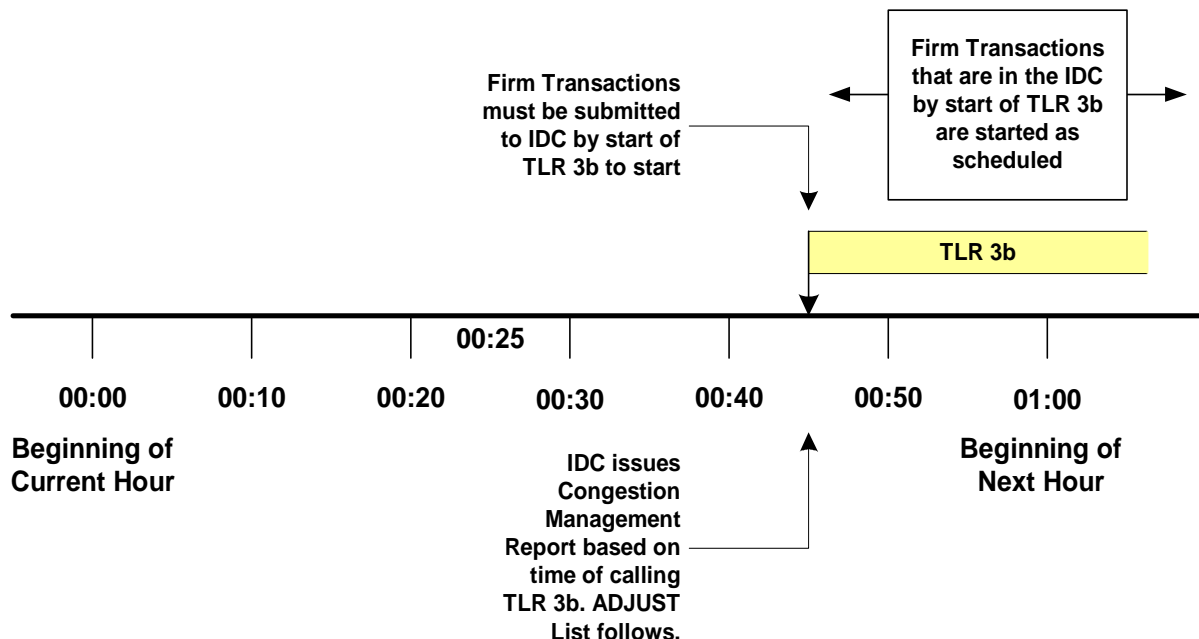
Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC after 00:25 will be held.

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:

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.

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.



The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.

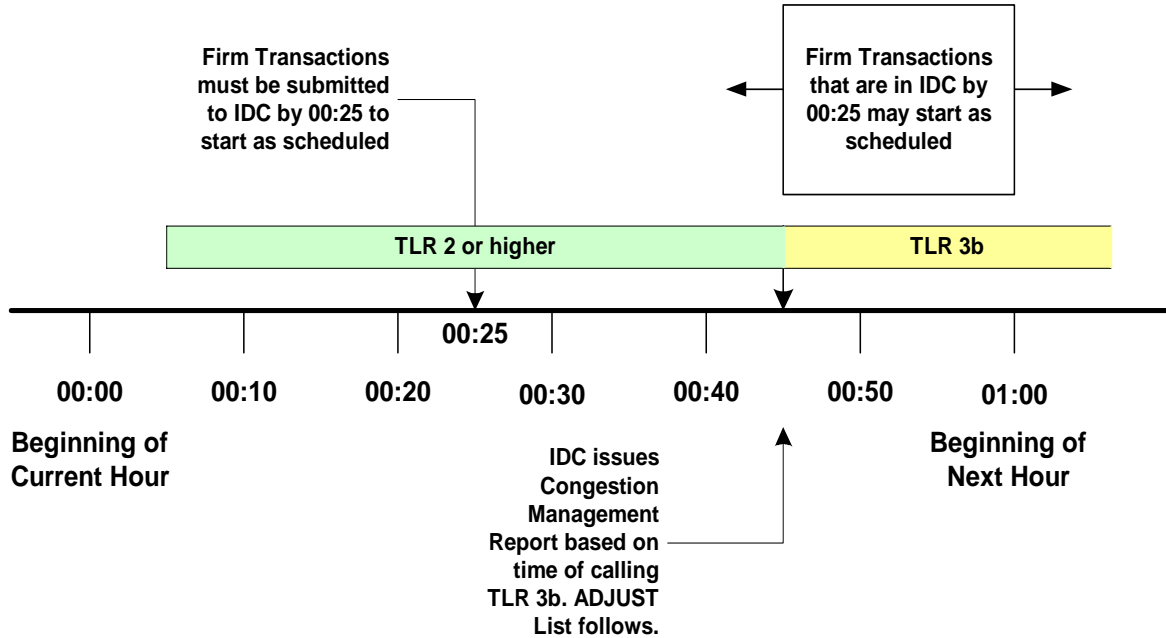
The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start at as scheduled.

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.

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.

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).

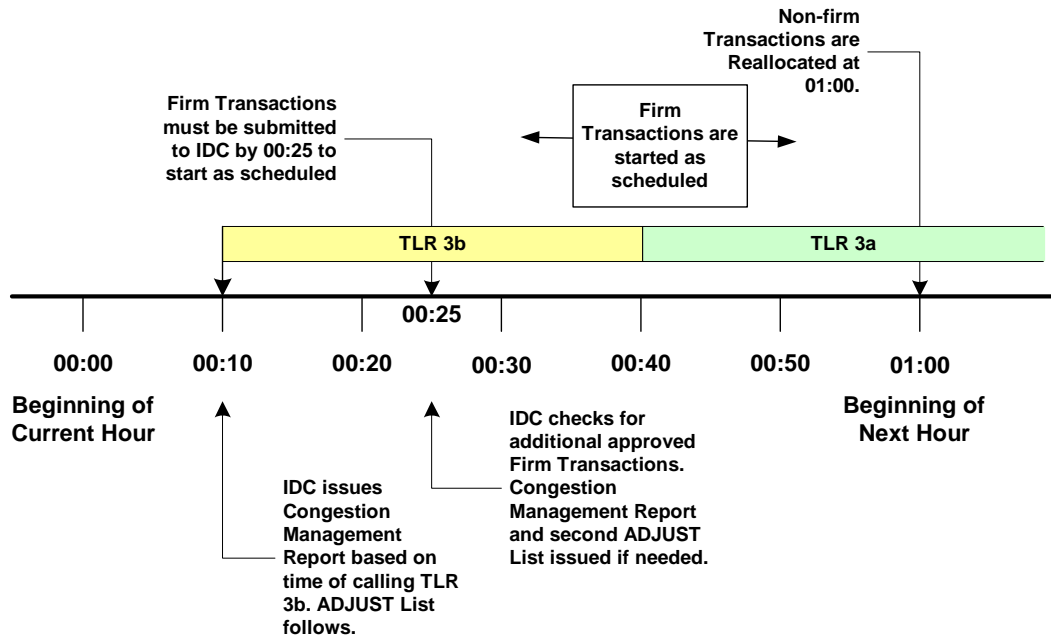
Case 3. TLR 2 or higher is in effect, a TLR 3b is called after 00:25, and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC by 00:25.



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.

Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief – Attachment 1

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.



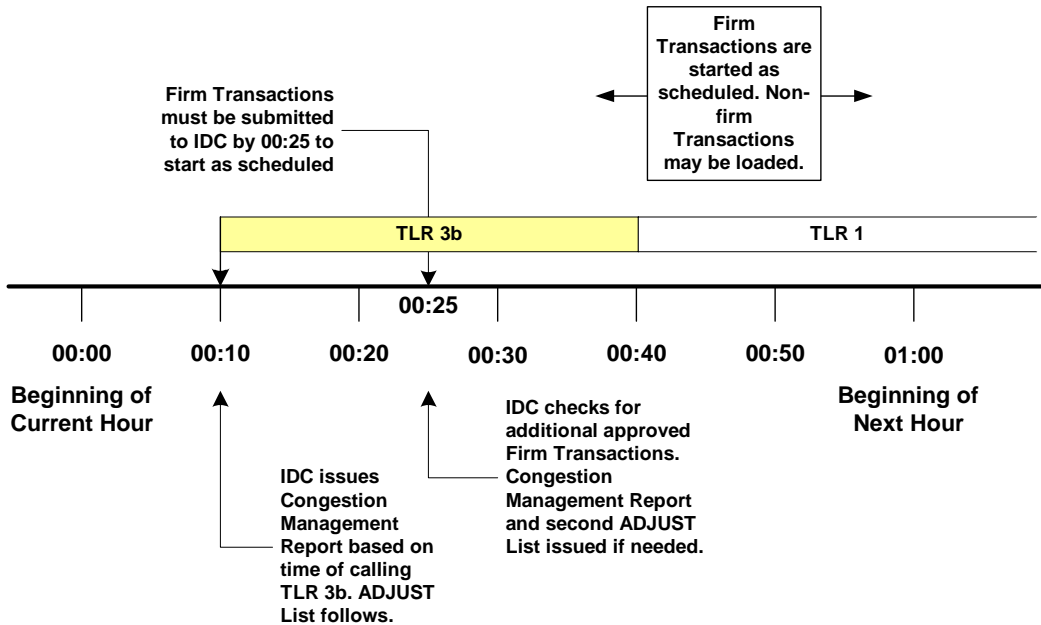
Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 3a.

All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled if in by the time the 3A is declared.

All Interchange Transactions using Non-firm Point-to-Point Transmission Service are reallocated at 01:00.

Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief – Attachment 1

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.



Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 1.

All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled.

All Interchange Transactions using Non-firm Point-to-Point Transmission Service may be loaded immediately.

White Paper on IRO-006 — Reliability Coordination – Transmission Loading Relief**Executive Summary**

As filed with FERC, the NERC Transmission Loading Relief (TLR) Standard Drafting Team has identified the reliability aspects of IRO-006 in a draft revision to the standard. The industry is being asked to review the draft revision (and associated Attachment 1) to determine whether or not the reliability objectives associated with the original standard have been maintained. In order to ensure industry understanding of these efforts, the Drafting Team has prepared the following documents:

- The draft reliability standard (both in redline and in clean formats),
- A draft Attachment 1 (both in redline and in clean formats),
- A [reference](#)¹ to the approved NAESB business practices (to show where commercial aspects will be covered), and
- An annotated mark-up of the original IRO-006 (highlighting how each part of the standard was divided).

Additionally, in response to industry comments, the team is developing a **Joint Operating Manual** that will provide operators with an integrated view of both the NERC and NAESB standards.

The work being presented for review is related only to the first phase of work that is to be undertaken by the drafting team, which is ensuring the division of the reliability and commercial aspects of IRO-006 continue to meet the needs of the industry. This includes the development of measures, compliance elements and other standard components to meet the requirements of the NERC Reliability Standards Development Procedure. Future phases are intended to provide support for changes to the MISO/PJM/SPP congestion management process, as well as improve the overall clarity of the standard.

In conducting the first phase of this work, the team attempted to retain the original requirements to the extent possible to avoid creating new elements that may precipitate lengthy debates hence delaying implementing the split. However, where in the judgment of the team the standard requirements as written were deemed to create difficulties in developing the necessary measures and compliance elements, the team modified the requirements to achieve those objectives.

Background

The original decision to separate the commercial and reliability standards was made in August, 2004, by the NERC Version 0 Standards Drafting Team and the

¹ Please access [http://naesb.org/misc/fa_weq_r06002_attachment%202 .pdf](http://naesb.org/misc/fa_weq_r06002_attachment%202.pdf) to review the NAESB TLR Business Practice Standards in conjunction with the proposed NERC TLR Reliability Standards to ensure that all relevant aspects of TLR standards are either included in the NERC proposal or in the NAESB business practices. Please note that the NAESB business practice standards are copyright protected. Should you need to obtain a copy of the NAESB standards for other purposes, please contact the NAESB office.

NAESB Business Practice Subcommittee (BPS). This decision was supported by the Joint Interface Committee, consisting of NERC, NAESB, and the IRC (ISO/RTO Council). The agreement was to begin with Version 0 standards for both organizations, meaning standards would be identical, and then to move to Version 1 by the end of 2005 which would totally separate commercial and reliability standards. Approval of Version 1 would then call for the retirement of the Version 0 standards. This decision was also endorsed by the NERC Operating Committee and the Standards Authorization Committee (now called the Standards Committee).

A Joint NERC/NAESB TLR Task Force was formed and held eight meetings to complete the separation. In June of 2005, this team voted unanimously on the separation and agreed that each organization would begin Version 1 work on their portion of the separated standards.

In June, 2005, the NAESB BPS began work on its portion of the split and completed its process with an approval of the Wholesale Electric Quadrant (WEQ) Executive Committee and a subsequent member ratification on April 10, 2006. The decision was made to hold the ratified business practice in abeyance until NERC completed its portion of the split so that both organizations could make their appropriate filings with the FERC at the same time.

NERC posted the approved split for industry comment and received 12 sets of comments, six in favor of the split and six against the split. Those submitting negative comments stated the following concerns: the future management and coordination of the standards; keeping the standards in one accessible location; and the inclusion of business practices in the Interchange Distribution Calculator (IDC) Reference Document. The Operating Reliability Subcommittee at that point asked NAESB to cease work on their business practices (November, 2005) but reconsidered their decision in May, 2006 and approved the development of a SAR and formation of the NERC TLR SAR Drafting Team for the Standard Authorization Committee's ~~(SAC's and now known as Standards Committee (SC))~~ consideration.

To address concerns stated by the industry surrounding the division of the commercial practices and reliability standards, NERC and NAESB Executive leadership developed a process for joint development and maintenance of standards. This process was approved by the NAESB Board in February, 2006 and the NERC Board of Trustees in May, 2006. In addition, both organizations filed reports with the FERC in February, 2006, stating they would use this process to complete the TLR split in February, 2006. The template outlines a joint process for the overall development of standards, the posting of draft standards, and the industry comment periods for those standards. It additionally provides for the joint publication of standards, if Executive Management so decides. The template/process will not change the rights of the ballot body to vote at NERC or the rights of the membership to vote at NAESB.

This template answers the concerns of the industry by providing a method by which standards that are jointly developed can be maintained in realistic synchronization. The template for joint standards development also provides for a method to jointly publish standards when the industry provides feedback that one manual with both standards is necessary.

FERC placed additional emphasis on the NERC/NAESB joint development process in Order 676, stating “The WEQ also adopted business practice standards that complement NERC’s Version 0 reliability standards. The development of such standards will be of increasing importance in the future as the Commission approves reliability standards under the recently enacted Energy Policy Act of 2005 (EPAAct 2005).² Business practice and reliability standards must complement each other to support an efficient grid. Companies need to have means of conducting business that ensure compliance with the reliability standards. We, therefore, are pleased NERC and NAESB have developed operating protocols that synchronize their standards development to provide for efficient and coordinated implementation of their respective standards.”³ The support of the Commission for joint standards development and the commitment by both NERC and NAESB to complete the joint standards drafting for TLR standards, illustrates the importance of the task at hand to the Commission and to the industry.

The Work Scope of the NERC Drafting Team

NERC issued a SAR for TLR in December, 2006 to complete three phases of drafting work. The three phases include:

Phase 1 - - A coordinated effort with NAESB to clarify and refine the steps in the Transmission Loading Relief Procedure for the Eastern Interconnection to reaffirm the steps needed to support reliability and the steps needed to support the business practice. This should be accomplished as soon as possible and should not wait for other technical changes to the standard.

Phase 2 - A second set of modifications to this standard involves further consideration of a change to the market flow calculation specified in PJM/MISO and SPP regional differences E.1 and E.2 in Standard IRO-006-03 to address a reliability issue when MISO, PJM and SPP are unable to meet their relief obligations during TLR. The proposed modification would change the market flow threshold for MISO, PJM and SPP from 0% to 3%. Based on stakeholder comments, (submitted with the SAR to Modify IRO-006 for Market Information), this change needs to be field tested to verify that it would not have any unforeseen adverse consequences. The field test will start June 1, 2007 for PJM; MISO and SPP will join the field test in September 2007. The field test is expected to end May 31, 2008. This change would replace the SPP Urgent

² Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005), 42 U.S.C. 15801 et seq. See Order Nos. 672 and 672-A.

³ See Order 676 at para. 14.

Action Regional Difference to IRO-006. Since the end of the field test will not be completed before the SPP Urgent Action expires, SPP will need to take steps to extend the Urgent Action for one year. Since there was a delay in the start of the field test, changes related to Phase 2 will likely be introduced after the completion of Phase 3.

The PJM/MISO and SPP Regional Differences are also contained in the NAESB Business Practice, Appendix D – Sections A&B. Upon completion of the field test these Regional Differences will be removed from the NERC Standard.

Phase 3 - A third set of modifications includes the changes needed to elevate the overall quality of the standard and to address the additional technical issues that have been posed with this standard by stakeholders and FERC (see Standard Review Form and Reliability Standard Review Guidelines). In addition to revising the IDC Reference Document, the development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Part of the team's task is to ensure the reliability portion of the standard is enforceable as a mandatory reliability standard with financial penalties — the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear. The team is also tasked with incorporating other general issues needed to elevate the quality of the standard and to bring the format of the standard into compliance with the ERO Rules of Procedure as described in the standards development work plan (see Standard Review Form and Standard Review Guidelines). IRO-006 was developed as a Version 0 standard and although it has been updated to address some specific technical concerns, the SARs associated with the changes made to the standard limited modifications to just those modifications that were immediately needed. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to stand up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

Status

The team has drafted revisions to the NERC TLR Reliability Standard and is seeking industry comment. Supporting documents are being posted so that industry participants can understand the history of how the decision was made and approved to split commercial and business practice language. These documents include:

1. The draft reliability standard (both in redline and in clean formats),
2. A draft Attachment 1 (both in redline and in clean formats),
3. A reference⁴ to the approved NAESB business practices (to show where commercial aspects will be covered), and
4. An annotated mark-up of the original IRO-006 (highlighting how each part of the standard was divided).

Next Steps

The TLR drafting team will consider industry comments made on the NERC portion of the TLR standard and make any language revisions they stakeholders deem appropriate. Once the NERC community is comfortable with the reliability portion of the TLR standard and votes to approve, they will file the Phase 1 portion of the completed standards with the FERC. It is the suggestion of the joint drafting team that NAESB wait to file until NERC has completed its Phase 1 process; this recommendation is not intended to bind NAESB to a particular filing date.

Following the completion of this initial phase of work, the group will begin submitting Phase 2 and 3 changes to industry for comment and balloting.

⁴ Please access [http://naesb.org/misc/fa_weq_r06002_attachment%202 .pdf](http://naesb.org/misc/fa_weq_r06002_attachment%202.pdf) to review the NAESB TLR Business Practice Standards in conjunction with the proposed NERC TLR Reliability Standards to ensure that all relevant aspects of TLR standards are either included in the NERC proposal or in the NAESB business practices. Please note that the NAESB business practice standards are copyright protected. Should you need to obtain a copy of the NAESB standards for other purposes, please contact the NAESB office.

Comment Form — Draft Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief

Please use this form to submit comments on the first draft of the TLR procedure NERC/NAESB split for the Eastern Interconnection (IRO-006-4 — Reliability Coordination — Transmission Loading Relief – Attachment 1). Comments must be submitted by **June 14, 2007**. You must submit the completed form by e-mail to sarcomm@nerc.net with the words **"NERC/NAESB TLR Split"** in the subject line. If you have questions please contact Andy Rodriquez at andy.rodriquez@nerc.net or 609-947-3885.

| Individual Commenter Information (Complete this page for comments from one organization or individual.) | | |
|---|--------------------------|--|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| NERC Region | | Registered Ballot Body Segment |
| <input type="checkbox"/> ERCOT | <input type="checkbox"/> | 1 — Transmission Owners |
| <input type="checkbox"/> FRCC | <input type="checkbox"/> | 2 — RTOs and ISOs |
| <input type="checkbox"/> MRO | <input type="checkbox"/> | 3 — Load-serving Entities |
| <input type="checkbox"/> NPCC | <input type="checkbox"/> | 4 — Transmission-dependent Utilities |
| <input type="checkbox"/> RFC | <input type="checkbox"/> | 5 — Electric Generators |
| <input type="checkbox"/> SERC | <input type="checkbox"/> | 6 — Electricity Brokers, Aggregators, and Marketers |
| <input type="checkbox"/> SPP | <input type="checkbox"/> | 7 — Large Electricity End Users |
| <input type="checkbox"/> WECC | <input type="checkbox"/> | 8 — Small Electricity End Users |
| <input type="checkbox"/> NA – Not Applicable | <input type="checkbox"/> | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | <input type="checkbox"/> | 10 - Regional Reliability Organizations, and Regional Entities |

Comment Form — Draft Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief

Background Information

NERC and the North American Energy Standards Board (NAESB) last year finalized a procedure for coordinating the development of standards in areas that affect both reliability and business practices, such as power interchange and congestion management. This approach allows the reliability requirements to be developed through the NERC process and the business practices to be developed through the NAESB process, with the actual development work being done by a joint team sponsored by NERC and NAESB.

Thus the standards will be separate but closely integrated. This approach is more effective than previous efforts that assigned standards to either NERC or NAESB when the subject matter obviously contains both reliability and business practice elements.

On June 1–2, 2005, following an extensive joint process, the NERC NAESB TLR Subcommittee completed a review of and recommended split of both reliability and business practice requirements of the NERC TLR standard IRO-006.

NAESB completed its ratification of its respective [TLR business practices](#)¹ on April 10, 2006, with updates for an SPP regional difference and changes to TLR Levels 3b and 4 ratified on September 1, 2006.

Following completion of its SAR process, NERC formed a TLR Drafting Team in August 2006. The NERC TLR Drafting Team has been meeting jointly with the NAESB Wholesale Electric Quadrant (WEQ) Business Practices Subcommittee to complete the respective changes to the NERC TLR standard IRO-006 to document the previously agreed-upon NERC/NAESB split of the TLR requirements. In addition, the team has also developed measures, compliance elements and other standard elements to meet the requirements of the NERC Reliability Standards Development Procedure.

In conducting this work, the team attempted to retain the original IRO-006 requirements to the extent possible to avoid creating new elements that may precipitate lengthy debates hence delaying implementing the NERC/NAESB split. However, where in the judgment of the team the standard requirements as written were deemed to create difficulties in developing the necessary measures and compliance elements, the team modified the requirements to achieve those objectives.

The comment form is asking for comments ONLY on the changes to the draft NERC standard. The sections highlighted² in the mapping document for the draft standard are being recommended for retirement from the NERC TLR standard.

As part of the project plan for this effort, the drafting team envisions creating a joint operators' manual that will contain both the NERC and NAESB portions of the TLR procedure.

¹ Please access http://naesb.org/misc/fa_weq_r06002_attachment%202.pdf to review the NAESB TLR Business Practice Standards in conjunction with the proposed NERC TLR Reliability Standards to ensure that all relevant aspects of TLR standards are either included in the NERC proposal or in the NAESB business practices. Please note that the NAESB business practice standards are copyright protected. Should you need to obtain a copy of the NAESB standards for other purposes, please contact the NAESB office.

² In the mapping of the NERC/NAESB TLR split, the following key is being used: Yellow — recommended for transfer to a new Attachment 2 in future work on the standard, Gray — agreed as being part of the NAESB Business Practices, Blue — to be deleted as obsolete in future work on the standard.

Comment Form — Draft Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief

Note that you do not have to answer all questions.

1. Do you agree that the new “Purpose” statement captures the intent of the standard? If not, please explain your answer.

The original purpose stated “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.”

The new purpose states “The purpose of this standard is to provide a method to prevent and or manage congestion on the Bulk Electric System.”

Yes

No

Comments:

2. In order to develop appropriate measures and compliance elements for the requirements and hold the applicable reliability functions responsible for meeting these requirements, the team has removed Transmission Operator from the applicability list on the basis that the requirements in IRO-006-3 that apply to the Transmission Operators are either not applicable (Section 1.6.3, Attachment 1) or already covered by other standards (Sections 1.8.1 and 2.9.2, Attachment 1). Do you agree with the applicable entities defined in the standard? If not, please specify to which entities the standard should apply.

Yes

No

Comments:

3. The intent of the revised standard is to capture the reliability requirements of the former TLR procedure following the NERC/NAESB split. Do you agree that the draft revisions to the standard and Attachment 1 accomplished this objective? If not, please explain your answer.

Yes

No

Comments:

4. Do you agree with the violation risk factors proposed in the standard? If not, please explain your answer.

Yes

No

Comments:

**Comment Form — Draft Standard IRO-006-4 — Reliability Coordination —
Transmission Loading Relief**

5. Do you agree with the time horizons proposed in the standard? The drafting team was given the following criteria to use in assigning a “time horizon.” Note that time horizons are used as one component in determining the size of a sanction. More information about time horizons can be found in the Sanctions Guidelines.

- Long-term Planning — a planning horizon of one year or longer.
- Operations Planning — operating and resource plans from day-ahead up to and including seasonal.
- Same-day Operations — routine actions required within the timeframe of a day, but not real-time.
- Real-time Operations — actions required within one hour or less to preserve the reliability of the Bulk Electric System.
- Operations Assessment — follow-up evaluations and reporting of real time operations.

If not, please explain your answer.

Yes

No

Comments:

6. Do you agree with the measures proposed in the standard? If not, please explain your answer.

Yes

No

Comments:

7. Do you agree with the compliance elements proposed in the standard? If not, please explain your answer.

Yes

No

Comments:

8. The drafting team is planning a joint NERC NAESB TLR operator’s manual for the TLR procedure. What would your organization like to see contained in a joint manual?

Comments:

9. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If yes, please explain your answer.

Yes

No

Comments:

**Comment Form — Draft Standard IRO-006-4 — Reliability Coordination —
Transmission Loading Relief**

10. Do you have any concerns that would prevent you from voting to approve this draft standard? If yes, please explain your answer.

Yes

No

Comments:

11. Please provide any other comments you have (that you have not already provided in response to the above questions) regarding this draft standard.

Comments: