Exhibit A

Reliability Standards Proposed for Approval

Proposed New Standard IRO-006-5

A. Introduction

1. **Title: Reliability Coordination — Transmission Loading Relief (TLR)**
2. **Number: IRO-006-5**
3. **Purpose:** To ensure coordinated action between Interconnections when implementing Interconnection-wide transmission loading relief procedures to prevent or manage potential or actual SOL and IROL exceedances to maintain reliability of the bulk electric system.
4. **Applicability:**

   4.1. Reliability Coordinator.

   4.2. Balancing Authority.
5. **Proposed Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required; the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Reliability Coordinator and Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a reliability reason to the requestor why it cannot comply with the request. [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall provide evidence (such as dated logs, voice recordings, Tag histories, and studies, in electronic or hard copy format) that, when a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure was made from another Reliability Coordinator, Balancing Authority, or Transmission Operator in that other Interconnection, it complied with the request or provided a reliability reason why it could not comply with the request (R1).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   Regional Entity.

   1.2. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

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

- The Reliability Coordinator and Balancing Authority shall maintain evidence to show compliance with R1 for the most recent twelve calendar months plus the current month.
- If a Reliability Coordinator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				The responsible entity received a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority, or Transmission Operator, but the entity neither complied with the request, nor provided a reliability reason why it could not comply with the request.

E. Variances

None.

F. Associated Documents

None.

G. 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
4	October 23, 2007	Completed NERC/NAESB split	Revision
5	TBD	Removed Attachment 1 and made into a new standard, eliminated unnecessary requirements.	Revision
6	November 4, 2010	Approved by the Board of Trustees	

Proposed New Standard IRO-006-EAST-1

(Includes Proposed Definition for Market Flow)

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.

Market Flow: the total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve Load internal to the market.

A. Introduction

1. **Title: Transmission Loading Relief Procedure for the Eastern Interconnection**
2. **Number:** IRO-006-EAST-1
3. **Purpose:** To provide an Interconnection-wide transmission loading relief procedure (TLR) for the Eastern Interconnection that can be used to prevent and/or mitigate potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).
4. **Applicability:**
   4.1. Reliability Coordinators in the Eastern Interconnection.
5. **Proposed Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_V, each Reliability Coordinator shall initiate, prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated), one or more of the following actions: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

- Inter-area redispatch of generation
- Intra-area redispatch of generation
- Reconfiguration of the transmission system
- Voluntary load reductions (e.g., Demand-side Management)
- Controlled load reductions (e.g., load shedding)

R2. To ensure operating entities are provided with information needed to maintain an awareness of changes to the Transmission System, when initiating the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance, and at least every clock hour (with the exception of TLR-1, where an hourly update is not required) after initiation up to and including the hour when the TLR level has been identified as TLR Level 0, the Reliability Coordinator shall identify: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

2.1. A list of congestion management actions to be implemented, and

2.2. One of the following TLR levels: TLR-1, TLR-2, TLR-3A, TLR-3B, TLR-4, TLR-5A, TLR-5B, TLR-6, TLR-0 [1]

[1] For more information on TLR levels, please see "Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels Reference Document."

R3. Upon the identification of the TLR level and a list of congestion management actions to be implemented, the Reliability Coordinator initiating this TLR procedure shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

3.1. Notify all Reliability Coordinators in the Eastern Interconnection of the identified TLR level

3.2. Communicate the list of congestion management actions to be implemented to 1.) all Reliability Coordinators in the Eastern Interconnection, and 2.) those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions.

3.3. Request that the congestion management actions identified in Requirement R2, Part 2.1 be implemented by:

1.) Each Reliability Coordinator associated with a Sink Balancing Authority for which Interchange Transactions are to be curtailed,

2.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which Network Integration Transmission Service or Native Load is to be curtailed, and

3.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which its Market Flow is to be curtailed.

R4. Each Reliability Coordinator that receives a request as described in Requirement R3, Part 3.3. shall, within 15 minutes of receiving the request, implement the congestion management actions requested by the issuing Reliability Coordinator as follows: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

- Instruct its Balancing Authorities to implement the Interchange Transaction schedule change requests.
- Instruct its Balancing Authorities to implement the Network Integration Transmission Service and Native Load schedule changes for which the Balancing Authorities are responsible.
- Instruct its Balancing Authorities to implement the Market Flow schedule changes for which the Balancing Authorities are responsible.
- If an assessment determines shows that one or more of the congestion management actions communicated in Requirement R3, Part 3.3 will result in a reliability concern or will be ineffective, the Reliability Coordinator may replace those specific actions with alternate congestion management actions, provided that:
  - The alternate congestion management actions have been agreed to by the initiating Reliability Coordinator, and
  - The assessment shows that the alternate congestion management actions will not adversely affect reliability.

C. Measures

M1. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that when acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_v, the Reliability Coordinator initiated one or more of the actions listed in R1 prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated)(R1).

M2. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that at the time it initiated the Eastern Interconnection TLR procedure, and at least every clock hour after initiation up to and including the hour when the TLR level was identified as TLR Level 0, the Reliability Coordinator identified both the TLR Level and a list of congestion management actions to be implemented (R2).

M3. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that after it identified a TLR level and a list of congestion management actions to take, it 1.) notified all Reliability Coordinators in the Eastern Interconnection of the TLR Level, 2.) communicated the list of actions to all Reliability Coordinators in the Eastern Interconnection and those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions, and 3.) requested the Reliability Coordinators identified in Requirement R3 Part 3.2 to implement the congestion management actions identified in Requirement R2 Part 2.1 (R3).

M4. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that within fifteen minutes of the receipt of a request as described in R3, the Reliability Coordinator complied with the request by either 1.) implementing the communicated congestion management actions requested by the issuing Reliability Coordinator, or 2.) implementing none or some of the communicated congestion management actions requested by the issuing Reliability Coordinator, and replacing the remainder with alternate congestion management actions if assessment showed that some or all of the congestion management actions communicated in R3 would have resulted in a reliability concern or would have been ineffective, the alternate congestion management actions were agreed to by the initiating Reliability Coordinator, and assessment showed that the alternate congestion management actions would not adversely affect reliability (R4).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications

- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.3. Data Retention

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

- The Reliability Coordinator shall maintain evidence to show compliance with R1, R2, R3, and R4 for the past 12 months plus the current month.
- If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

3. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_v, the Reliability Coordinator did not initiate one or more of the actions listed under R1 prior to or in conjunction with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated).
R2	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for one clock hour during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for two clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for three clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for four or more clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level (3.1).	N/A	The initiating Reliability Coordinator did not communicate the list of congestion management actions to one or more of the Reliability Coordinators listed in Requirement R3, Part 3.2. OR The initiating Reliability Coordinator requested some, but not all, of the Reliability Coordinators identified in Requirement R3, Part 3.3 to implement the identified congestion management actions.	The initiating Reliability Coordinator requested none of the Reliability Coordinators identified in Requirement R3, Part 3.3 to implement the identified congestion management actions.
R4				The responding Reliability Coordinator did not, within 15 minutes of receiving a request, either 1.) implement all the requested congestion management actions, or 2.) implement none or some of the requested congestion management actions and replace the remainder with alternate congestion

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				management actions, provided that: assessment showed that the actions replaced would have resulted in a reliability concern or would have been ineffective, the alternate congestion management actions were agreed to by the initiating Reliability Coordinator, and assessment determined that the alternate congestion management actions would not adversely affect reliability.

E. Variances

None.

F. Associated Documents

Implementation Guideline for Reliability Coordinators:
Eastern Interconnection TLR Levels Reference Document

G. Revision History

Version	Date	Action	Tracking
1		Creation of new standard, incorporating concepts from IRO-006-4 Attachment; elimination of Regional Differences, as the standard allows the use of Market Flow	New

Exhibit B

Reliability Standard IRO-006-4.1 Proposed for Retirement

A. Introduction

1. **Title:** **Reliability Coordination — Transmission Loading Relief (TLR)**

2. **Number:** IRO-006-4.1

3. **Purpose:** The purpose of this standard is to provide Interconnection-wide transmission loading relief procedures that can be used to prevent or manage potential or actual SOL and IROL violations to maintain reliability of the Bulk Electric System.

4. **Applicability:**

   4.1. Reliability Coordinators.

   4.2. Transmission Operators.

   4.3. Balancing Authorities.

5. **Effective Date:** December 10, 2009

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 due to the time required to implement the procedure. 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 WECC Unscheduled Flow Reduction Procedure 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. Each Reliability Coordinator with a relief obligation from an Interconnection-wide procedure 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 of the local procedure from 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

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 evidence for eighteen months for M1, M4, and M5.

The Reliability Coordinator shall maintain evidence 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 evidence 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).

2.1.3 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).

2.2. Moderate. There shall be a moderate violation severity level if any of the following conditions exist:

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

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 violated 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 from 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

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.

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.

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	The Transaction would not be allowed

	started and was submitted to the Tag Authority after the TLR (level 2 or higher) has been declared to begin flowing (i.e., the Interchange Transaction never had an active MW and was submitted to the IDC after the first TLR Action of the TLR Event had been declared.)	to start until all other Interchange Transactions submitted prior to the TLR with the same priority have been (re)loaded. The MW amount used is the sub-priority is the next-hour schedule determined by the e-tag ENERGY PROFILE table.

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 fist 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
4	October 23, 2007	Approved by Board of Trustees	Revision
4.1	April 15, 2009	The URL in R1.2. was corrected.	Errata
4.1	December 10, 2009	Approved by FERC — Added approved effective date	Update

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.

1.1.1. Requesting relief on transmission facilities. Any Transmission Operator may request from its Reliability Coordinator relief on the transmission facilities it operates. A Reliability Coordinator shall review these requests for relief and determine the appropriate relief actions.

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

1.3. 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 the appropriate NERC web page(s).

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

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.

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.

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.

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.

formerly NERC section 3.3

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.

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.

2.10 TLR Level 0 — TLR concluded

2.10.1 **Interchange Transaction restoration and notification procedures.** The Reliability Coordinator initiating the TLR Procedure shall notify all Reliability Coordinators within the Interconnection via the RCIS when the SOL or IROL violations are mitigated and the system is in a reliable state, allowing Interchange Transactions to be reestablished at its discretion. Those with the highest transmission priorities shall be reestablished first if possible.

3. Requirements

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

3.2 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:

3.2.1 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

3.2.2 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.

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

3.3 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: (recommended to be moved to Attachment 2)

3.3.1 Interchange Transactions using Non-firm Point-to-Point Transmission Service that are to be curtailed or held during current and next hours. (recommended to be moved to Attachment 2)

3.3.2 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). (recommended to be moved to Attachment 2)

3.4 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. (recommend to be moved to Attachment 2)

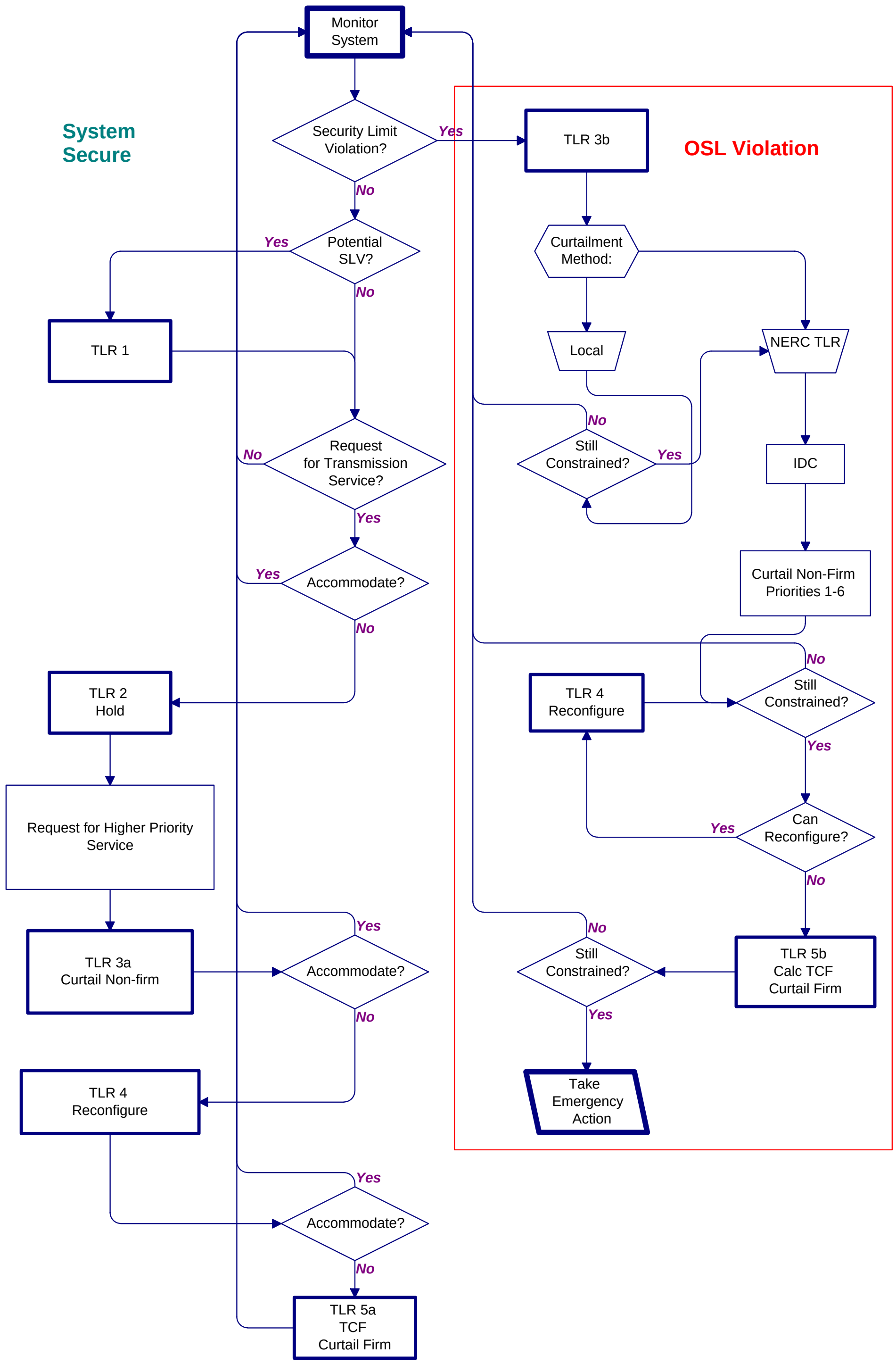
3.5 The Reliability Coordinator will no longer be required to call a TLR Level 3a as soon as the SOL or IROL violation that caused the TLR 3b to be called has been mitigated due to the inherent next hour Reallocation that takes place for the top of the next hour in the TLR Level 3b. (recommend to be moved to Attachment 2)

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

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



Appendix C. Sample NERC Transmission Loading Relief Procedure Log

SAVE FILE DIRECTORY:

NERC TRANSMISSION LOADING RELIEF (TLR) PROCEDURE LOG

FILE SAVED AS: .XLS

INCIDENT:	DATE:	IMPACTED RELIABILITY COORDINATOR:	ID NO:

INITIAL CONDITIONS

Limiting Flowgate (LIMIT)	Rating	Contingent Flowgate (CONT.)	ODF

TLR Levels

0: TLR Incident Canceled
1. Notify Reliability Coordinators of potential problems.
2: Halt additional transactions that contribute to the overload
3a and 3b: Curtail transactions using Non-firm Transmission Service
4. Reconfigure to continue firm transactions if needed.
5a and 5b: Curtail Transactions using Firm Transmission Service.
6: Implement emergency procedures.

Priorities

NX	Next Hour Market Service
NS	Service over secondary receipt and delivery points
NH	Hourly Service
ND	Daily Service
NW	Weekly Service
NM	Monthly Service
NN	Non-firm imports for native load and network customers from non-designated network resources
F	Firm Service

TLR ACTIONS

LEVEL	TIME	Priority	TLR 3,5 No. TX Curtail	TLR 3,5 MW Curtai	MW Flow Limiting Element Present	MW Flow Limiting Element Post Cont.	MW Flow Cont. Elem't Present	COMMENTS ABOUT ACTIONS

Appendix E. How the IDC Handles Reallocation

The IDC algorithms reflect the Reallocation and reloading principles in this Appendix, as well as the reporting requirements, and status display. The IDC will obtain the Tag Submittal Time from the Tag Authority and post the Reloading/Reallocation information to the NERC TLR website.

A summary of IDC features that support the Reallocation process is provided in Attachment E1. Details on the interface and display features are provided in Attachment E2. Refer to Version 1.7.095 NERC Transaction Information Systems Working Group (TISWG) *Electronic Tagging Functional Specification* for details about the E-Tag system.

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

The following is a summary of IDC features and E-Tag interface that support Reloading/Reallocation:

Information posted from IDC to NERC TLR website.

1. Restricted directions (all source/sink combinations that impact a Constrained Facility(ies) with TLR 2 or higher) will be posted to the NERC TLR website and updated as necessary.
2. TLR Constrained Facility status and Transfer Distribution Factors will continue to be posted to NERC TLR website.
3. Lowest priority of Interchange Transactions (marginal "bucket") to be Reloaded/Reallocated next-hour on each TLR Constrained Facility will be posted on NERC TLR website. This will provide an indication to the market of priority of Interchange Transactions that may be Reloaded/Reallocated the following hours.

IDC Logic, IDC Report, and Timing

1. The Reliability Coordinator will run the IDC the Reloading/Reallocation report at approximately 00:26. The IDC will prompt the Reliability Coordinator to enter a maximum loading value. The IDC will alarm if the Reliability Coordinator does not enter this value and issue a report by 00:30 or change from TLR 3a Level. The Report will be distributed to Balancing Authorities and Transmission Operators at 00:30. This process repeats every hour as long as the approved tag submission deadline for Reallocation is in effect (or until the TLR level is reduced to 1 or 0).
2. For Interchange Transactions in the restricted directions, tags must be submitted to the IDC by the approved tag submission deadline for Reallocation to be considered for Reallocation next-hour. The time stamp by the Tag Authority is regarded the official tag submission time.
3. Tags submitted to IDC after the approved tag submission deadline for Reallocation will not be allowed to start or increase but will be considered for Reallocation the next hour.
4. Interchange Transactions in restricted directions that are not indicated as "PROCEED" on the Reload/Reallocation Report will not be permitted to start or increase next hour.

Reloading/Reallocation Transaction Status

Reloading/Reallocation status will be determined by the IDC for all Interchange Transactions. The Reloading/Reallocation status of each Interchange Transaction will be listed on IDC reports and NERC TLR website as appropriate. An Interchange Transaction is considered to be in a restricted direction if it is at or above the Curtailment Threshold. Interchange Transactions below the Curtailment Threshold are unrestricted and free to flow subject to all applicable Reliability Standards and tariff rules.

1. **HOLD.** Permission has not been given for Interchange Transaction to start or increase and is waiting for the next Reloading/Reallocation evaluation for which it is a candidate. Interchange Transactions with E-tags submitted to the Tag Authority prior to TLR 2 or higher being declared (pre-tagged) will change to CURTAILED Status upon evaluation that does not permit them to start or increase.

Transactions with E-tags submitted to Tag Authority after TLR 2 or higher was declared (post-tagged) will retain HOLD Status until given permission to proceed or E-Tag expires.

2. **CURTAILED**. Transactions for which E-Tags were submitted to Tag Authority prior to TLR 2 or higher being declared (pre-tagged) and ordered to be curtailed totally, curtailed partially, not permitted to start, or not permitted to increase. Interchange Transactions (pre-tagged or post-tagged) that were flowing and ordered to be reduced or totally curtailed. The Balancing Authority will indicate to the IDC through the E-Tag adjustment table the Interchange Transaction's curtailed values.

3. **PROCEED**: Interchange Transaction is flowing or has been permitted to flow as a result of Reloading/Reallocation evaluation. The Balancing Authority will indicate through the E-Tag adjustment table to IDC if Interchange Transaction will reload, start, or increase next-hour per Purchasing-Selling Entity's energy schedule as appropriate.

Reallocation/Reloading Priorities

1. Interchange Transaction candidates are ranked for loading and curtailment by priority as per Section 4, "Principles for Mitigating Constraints On and Off the Contract Path." This is called the "Constrained Path Method," or CPM. (secondary, hourly, daily, … firm etc). Interchange Transactions are curtailed and loaded pro-rata within priority level per TLR algorithm.
2. Reloading/Reallocation of Interchange Transactions are prioritized first by priority per CPM. E-Tags must be submitted to the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is scheduled to start or increase to be considered for Reallocation.
3. During Reloading/Reallocation, Interchange Transactions using lower priority Transmission Service will be curtailed pro-rata to allow higher priority transactions to reload, increase, or start. Equal priority Interchange Transactions will not reload, start, or increase by pro-rata Curtailment of other equal priority Interchange Transactions.
4. Reloading of Interchange Transactions using Non-firm Transmission Service with CURTAILED Status will take precedence over starting or increasing of Interchange Transactions using Non-firm Transmission Service of the same priority with PENDING Statuses.
5. Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled under TLR 3a as long as their E-Tag was received by the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is due to start or increase, regardless of whether the E-tag was submitted to the Tag Authority prior to TLR 2 or higher being declared or not. If this is the initial issuance of the TLR 3a, Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled as long as their E-Tag was received by the IDC by the time the TLR is declared.

Total Flow Value on a Constrained Facility for Next Hour

1. The Reliability Coordinator will calculate the change in net flow on a Constrained Facility due to Reallocation for the next hour based on:

- Present constrained facility loading, present level of Interchange Transactions, and Balancing Authorities NNative Load responsibility (TLR Level 5a) impacting the Constrained Facility,
- SOLs or IROLs, known interchange impacts and Balancing Authority NNative Load responsibility (TLR Level 5a) on the Constrained Facility the next hour, and
- Interchange Transactions scheduled to begin the next hour.

2. The Reliability Coordinator will enter a maximum loading value for the constrained facility into the IDC as part of issuing the Reloading/Reallocation report.
3. The Reliability Coordinator is allowed to call for TLR 3a or 5a when approaching a SOL or IROL to allow maximum transactional flow next hour, and to manage flows without violating transmission limits.
4. The simultaneous curtailment and Reallocation for a Constrained Facility is allowed. This reduces the flow over the Constrained Facility while allowing Interchange Transactions using higher priority Transmission Service to start or increase the next hour. This may be used to accommodate change in flow next-hour due to changes other than Point-to-Point Interchange Transactions while respecting the priorities of Interchange Transactions flowing and scheduled to flow the next hour. The intent is to reduce the need for using TLR 3b, which prevents new Interchange Transactions from starting or increasing the next hour.
5. The Reliability Coordinator must allow Interchange Transactions to be reloaded as soon as possible. Reloading must be in an orderly fashion to prevent a SOL or IROL violation from (re)occurring and requiring holding or curtailments in the restricted direction.

E2. Timing Requirements

TLR Levels 3a and 5a Issuing/Processing Time Requirement

1. In order for the IDC to be reasonably certain that a TLR Level 3a or 5a re-allocation/reloading report in which all tags submitted by the approved tag submission deadline for Reallocation are included, the report must be generated no earlier than 00:25 to allow the 10-minute approval time for Transactions that start next hour.
2. In order to allow a Reliability Coordinator to declare a TLR Level 3a or 5a at any time during the hour, the TLR declaration and Reallocation/Reloading report distribution will be treated as independent processes by the IDC. That is, a Reliability Coordinator may declare a TLR Level 3a or 5a at any time during the course of an hour. However, if a TLR Level 3a or 5a is declared for the next hour prior to 00:25 (see Figure 5 at right), the Reallocation/Reloading report that is generated will be made available to the issuing Reliability Coordinator only for previewing purposes, and cannot be distributed to the other Reliability Coordinators or the market. Instead, the issuing Reliability Coordinator will be reminded by an IDC alarm at 00:25 to generate a new Reallocation/Reloading report that will include all tags submitted prior to the approved tag submission deadline for Reallocation.

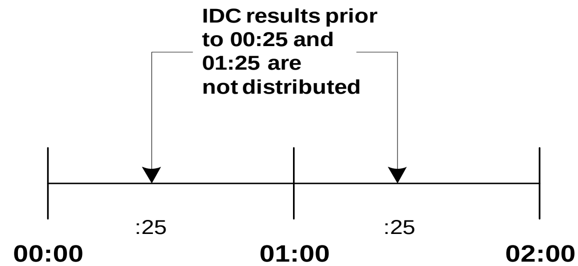


Figure 5 - IDC report may be run prior to 00:25, but results are not distributed.

3. A TLR Level 3a or 5a Reallocation/Reloading report must be confirmed by the issuing Reliability Coordinator prior to 00:30 in order to provide a minimum of 30 minutes for the Reliability Coordinators with tags sinking in its Reliability Area to coordinate the Reallocation and Reloading with the Sink Balancing Authorities. This provides only 5 minutes (from 00:25 to 00:30) for the issuing Reliability Coordinator to generate a Reallocation/Reloading report, review it, and approve it.
4. The TLR declaration time will be recorded in the IDC for evaluating transaction sub-priorities for Reallocation/Reloading purposes (see Subpriority Table, in the **IDC Calculations and Reporting** section below).

Re-Issuing of a TLR Level 2 or Higher

Each hour, the IDC will automatically remind the issuing Reliability Coordinator (via an IDC alarm) of a TLR level 2 or higher declared in the previous hour or earlier about re-issuing the TLR. The purpose of the reminder is to enable the Reliability Coordinator to Reallocate or reload currently halted or curtailed Interchange Transactions next hour. The reminder will be in the form of an alarm to the issuing Reliability Coordinator, and will take place at 00:25 so that, if the Reliability Coordinator re-issues the TLR as a TLR level 3a or 5a, all tags submitted prior to the approved tag submission deadline for Reallocation are available in the IDC.

IDC Assistance with Next Hour Point-to-Point Transactions

In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour for a TLR level 3a or 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour. In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour during a TLR level 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour as well as Balancing Authority with flows due to service to Network Customers and Native Load. The Reliability Coordinator will then be requested to provide the total incremental or decremental MW amount of flow through the Constrained Facility that can be allowed for the next hour. The value entered by the Reliability Coordinator and the IDC-calculated amounts will be used by the IDC to identify the relief/reloading amounts (delta incremental flow value) on the constrained facility. The IDC will determine the Transactions to be reloaded, reallocated, or curtailed to make room for the Transactions using higher priority Transmission Service. The following examples show the calculation performed by IDC to identify the "delta incremental flow:"

Example 1

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	-100 MW
Expected Net flow next hour on Facility	850 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	850 MW – 800 MW = 50 MW
Amount to enter into IDC for Transactions using Point-to-Point Transmission Service	950 MW – 50 MW = 900 MW

Example 2

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	50 MW
Expected Net flow next hour on Facility	1000 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	1000 MW – 800 MW = 200 MW
Amount to enter into IDC for Transactions using Point-to-Point Transmission Service	950 MW – 200 MW = 750 MW

Example 3

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	-200 MW
Expected Net flow next hour on Facility	750 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	750 MW – 800 MW = -50 MW None are held

For a TLR levels 3b or 5b the IDC will request the Reliability Coordinator to provide the MW requested relief amount on the Constrained Facility, and will not present the current and next hour MW impact of Point-to-Point transactions. The Reliability Coordinator-entered requested relief amount will be used by the IDC to determine the Interchange Transaction Curtailments and flows due to service to Network Customers and Native Load (TLR Level 5b) in order to reduce the SOL or IROL violation on the Constrained Facility by the requested amount.

IDC Calculations and Reporting

At the time the TLR report is processed, the IDC will use all candidate Interchange Transactions for Reallocation that met the approved tag submission deadline for Reallocation plus those Interchange Transactions that were curtailed or halted on the previous TLR action of the same TLR event. The IDC will calculate and present an Interchange Transactions Halt/Curtailment list that will include reload and Reallocation of Interchange Transactions. The Interchange Transactions are prioritized as follows:

1. All Interchange Transactions will be arranged by Transmission Service Priority according to the Constrained Path Method. These priorities range from 1 to 6 for the various non-firm Transmission Service products (TLR levels 3a and 3b). Interchange Transactions using Firm Transmission Service (priority 7) are used only in TLR levels 5a and 5b. Next-Hour Market Service is included at priority 0 (Recommended to be placed in Attachment 2).

   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

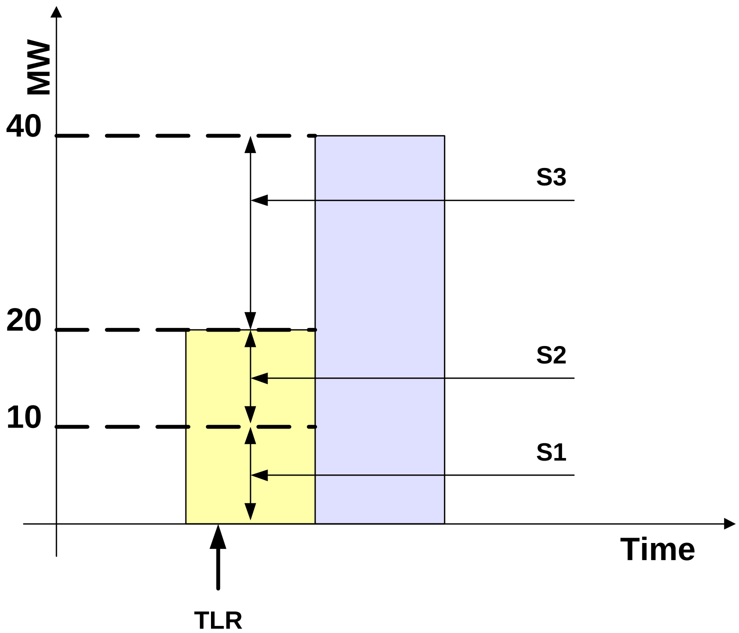
There are cases in which a tag may be marked with a composite state of ATTN_REQD to indicate that tag Authority/Approval failed to communicate or there is an inconsistency between the validation software of different tag Authority/Approval entities. In this situation, the tag is no longer subject to 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.

Example 1 – Transaction curtailed, next-hour Energy Profile is higher

Energy Profile: Current hour	20 MW
Actual flow following curtailment: Current hour	10 MW
Energy Profile: Next hour	40 MW

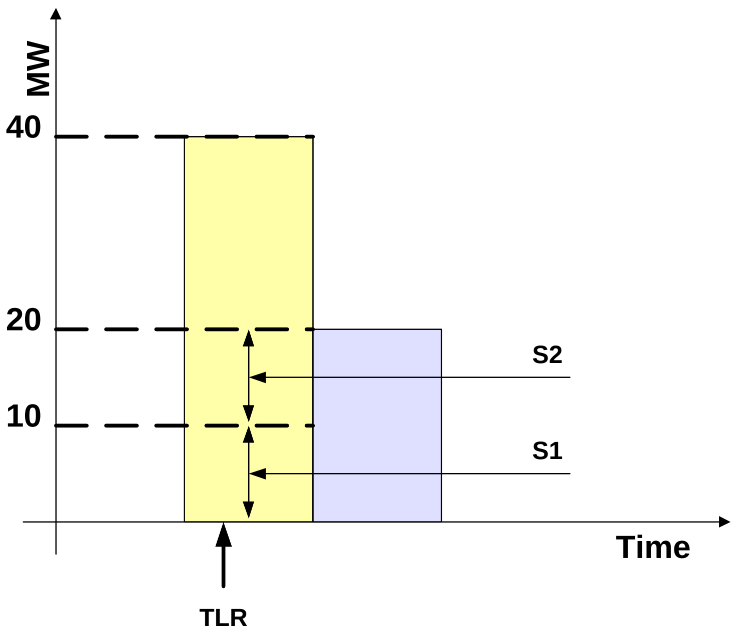


Sub-priorities for Transaction MW:

Sub-Priority	***MW Value***	***Explanation***
S1	10 MW	Maintain current curtailed flow
S2	+10 MW	Reload to current hour Energy Profile
S3	+20 MW	Load to next hour Energy Profile
S4		

Example 2 – Transaction curtailed, next-hour Energy Profile is lower

Energy Profile: Current hour	40 MW
Actual flow following curtailment: Current hour	10 MW
Energy Profile: Next hour	20 MW

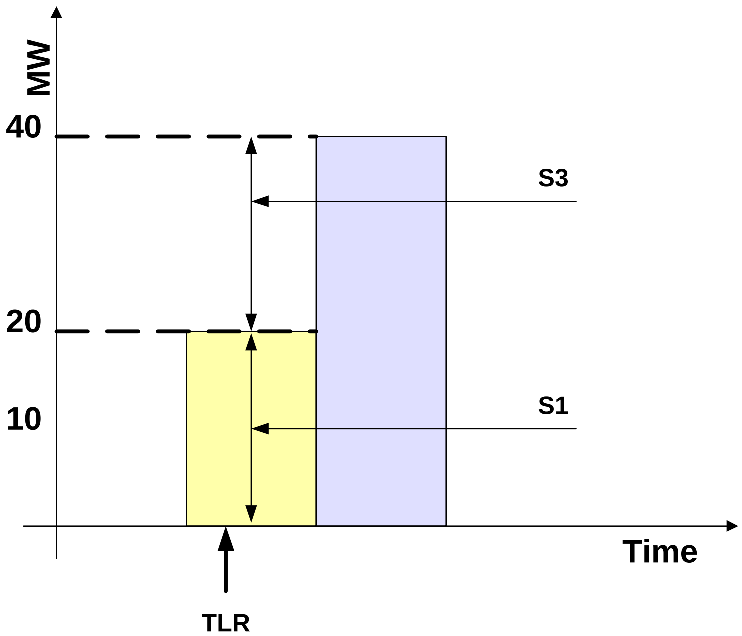


Sub-priorities for Transaction MW:

Sub-Priority	*MW Value*	*Explanation*
S1	10 MW	Maintain current curtailed flow
S2	+10 MW	Reload to *lesser* of current and next-hour Energy Profile
S3	+0 MW	Next-hour Energy Profile is 20MW, so no change in MW value
S4		

Example 3 – Transaction not curtailed, next-hour Energy Profile is higher

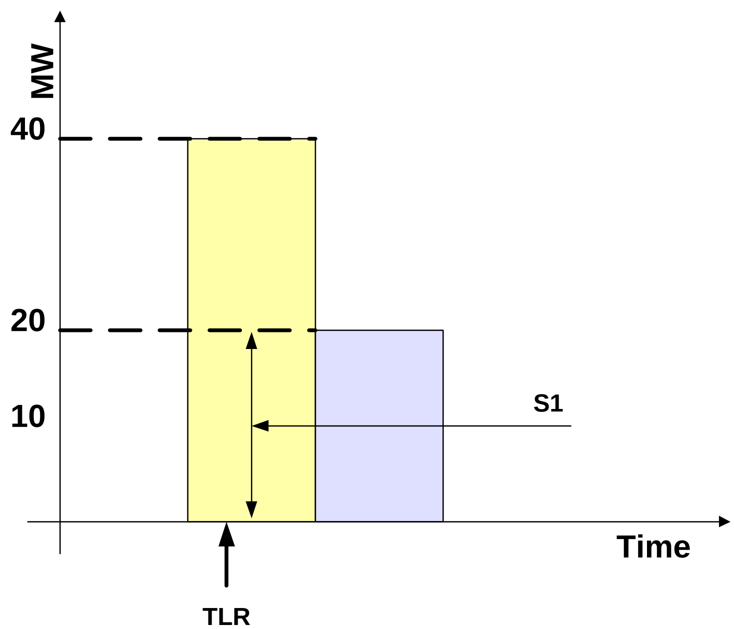
Energy Profile: Current hour	20 MW
Actual flow following curtailment: Current hour	20 MW (no curtailment)
Energy Profile: Next hour	40 MW



Sub-Priority	*MW Value*	*Explanation*
S1	20 MW	Maintain current flow (not curtailed)
S2	+0 MW	Reload to *lesser* of current and next-hour Energy Profile
S3	+20 MW	Next-hour Energy Profile is 40MW
S4		

Example 4 – Transaction not curtailed, next-hour Energy Profile is lower

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

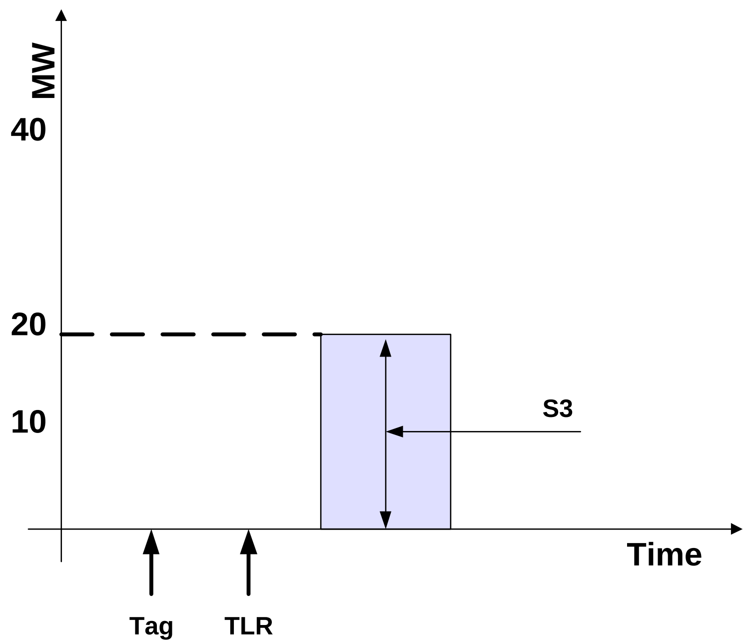


Sub-priorities for Transaction MW:

Sub-Priority	*MW Value*	*Explanation*
S1	20 MW	Reduce flow to next-hour Energy Profile (20MW)
S2	+0 MW	Reload to *lesser* of current and next-hour Energy Profile
S3	+0 MW	Next-hour Energy Profile is 20MW
S4		

Example 5 — TLR Issued before Transaction was scheduled to start

Energy Profile: Current hour	0 MW
Actual flow following curtailment: Current hour	0 MW (Transaction scheduled to start *after* TLR initiated)
Energy Profile: Next hour	20 MW



Sub-Priority	*MW Value*	*Explanation*
S1	0 MW	Transaction was not allowed to start
S2	+0 MW	Transaction was not allowed to start
S3	+20 MW	Next-hour Energy Profile is 20MW
S4	+0	Tag submitted prior to TLR

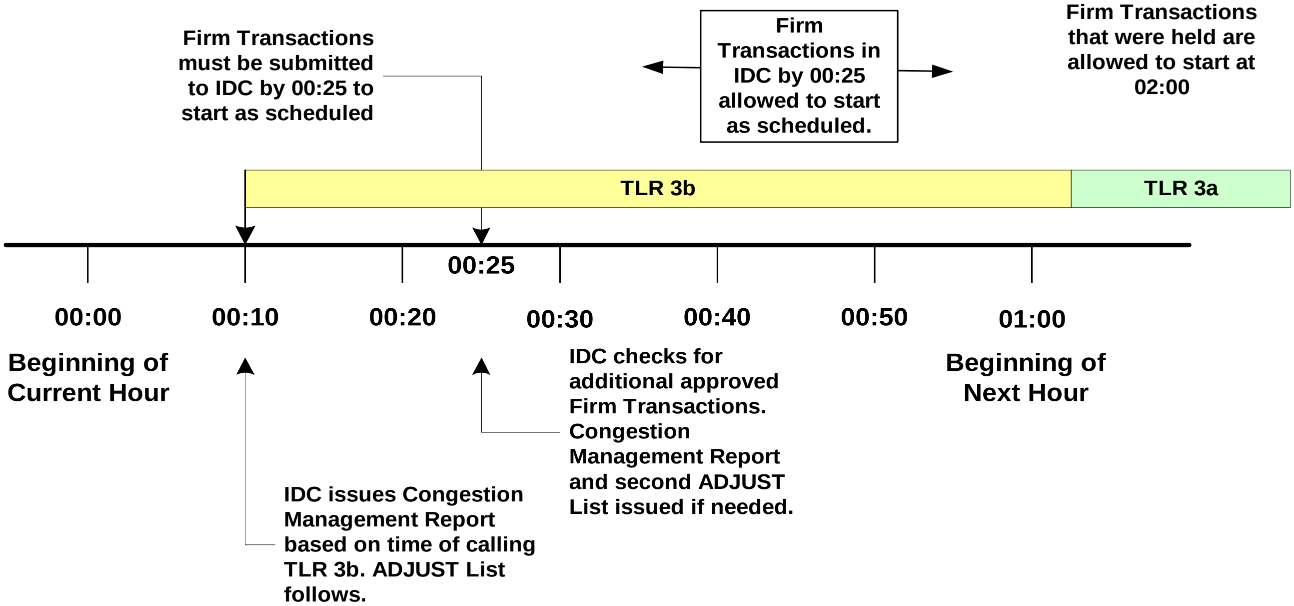
Appendix F. Considerations for Interchange Transactions

Using Firm Point-to-Point Transmission Service

The following cases explain the circumstances under which an Interchange Transaction using Firm Point-to-Point Transmission Service will be allowed to start as scheduled during a TLR 3b:

Case 1: TLR 3b is called between 00:00 and 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to IDC by 00:25.

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.

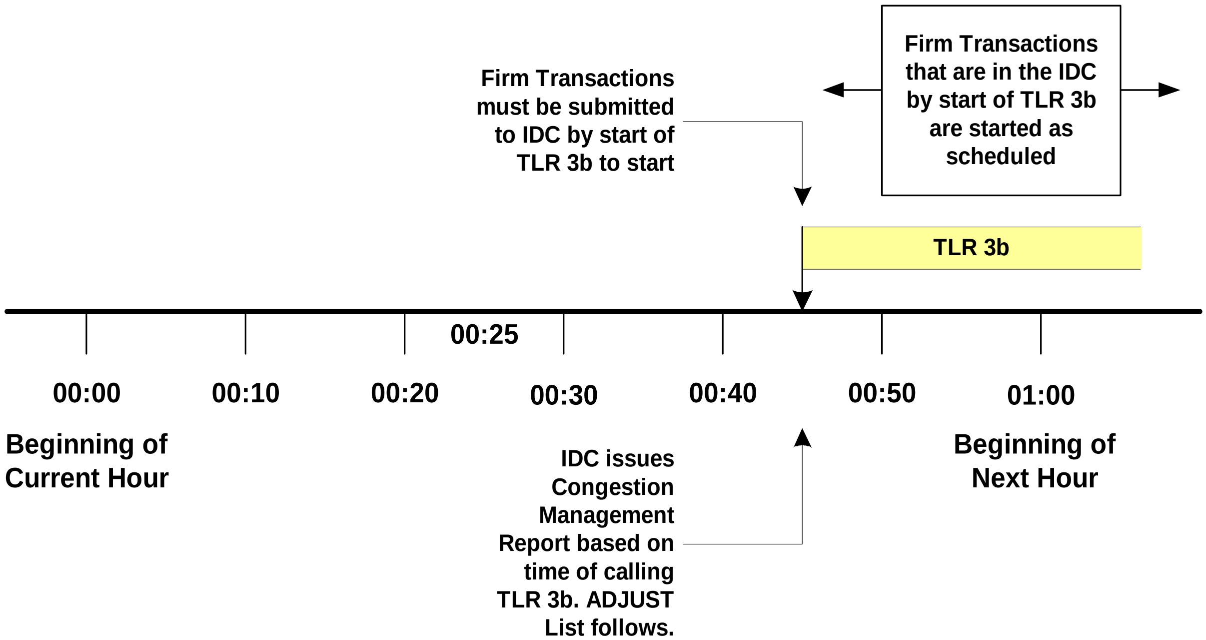
Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC after 00:25 will be held.

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.

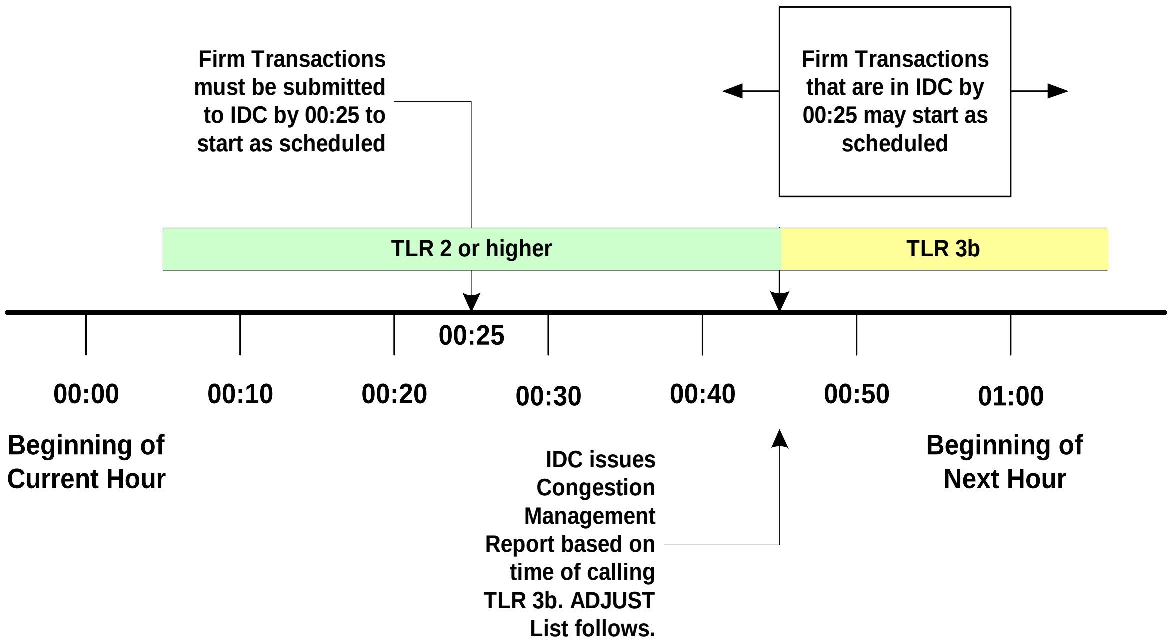
The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission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

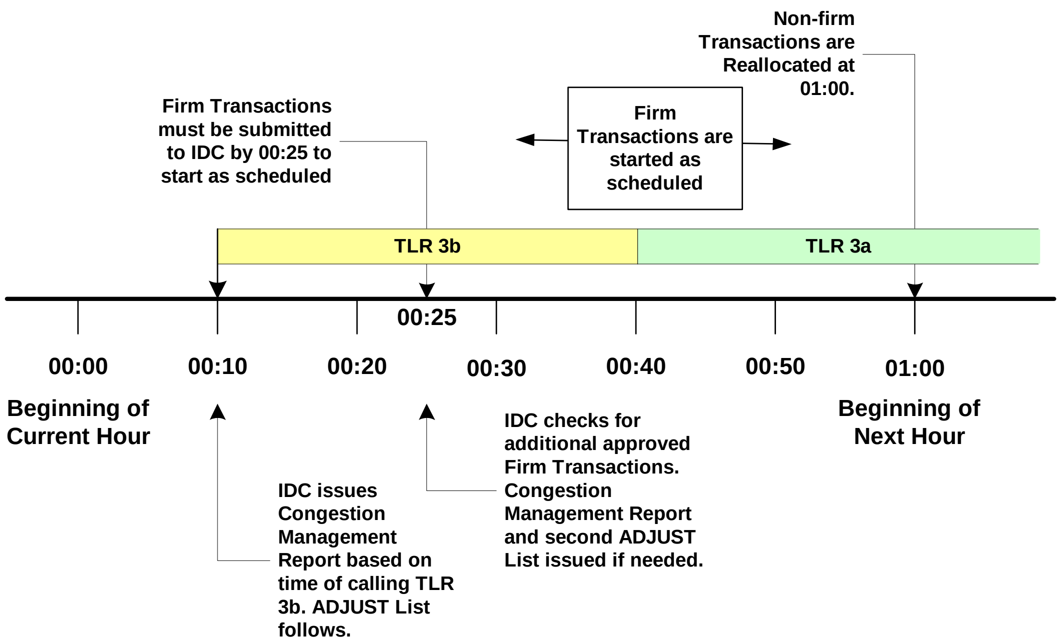
Interchange Transaction using Firm Point-to-Point Transmission Service that were submitted to the IDC after the TLR 3b was called will be held until the next issuance for TLR (either TLR 3b, 3a, or lower level).

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.

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.

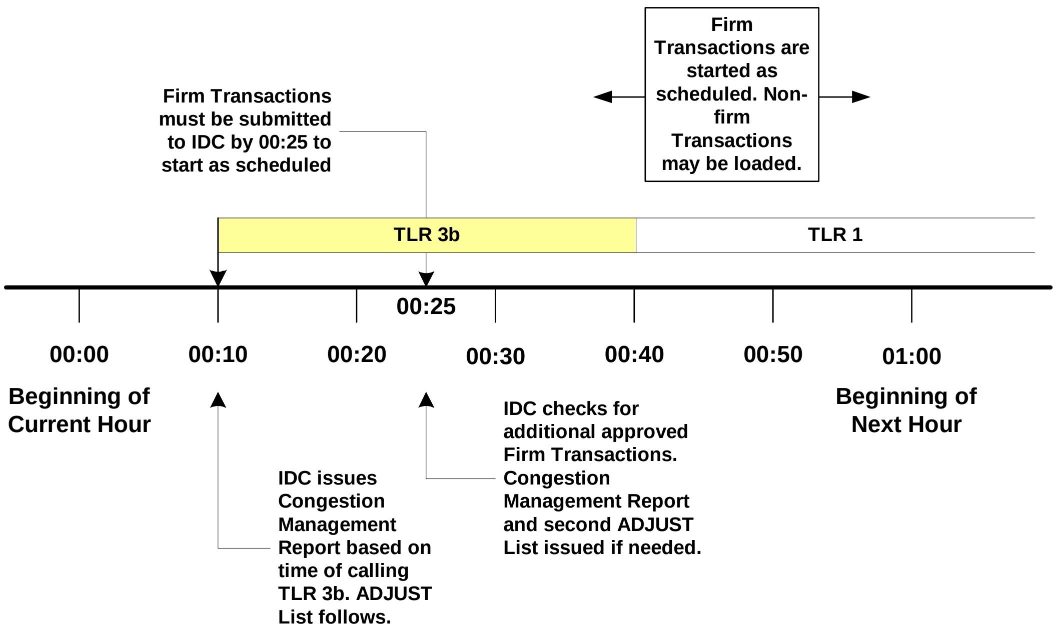


Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 3a.

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.

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.

Exhibit C

Proposed Implementation Plan

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for Standard IRO-006-5 (Reliability Coordination — Transmission Loading Relief (TLR)) and IRO-006-EI-1 (Loading Relief Procedure for the Eastern Interconnection)

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved or in progress, that must be implemented before these standards can be implemented.

Modified Definitions

The definition of "Reallocation" should be removed from the Glossary when IRO-006-5 and IRO-006-EI-1 become effective. The drafting team has verified that the term, "Reallocation" is not used in any other approved standard.

Modified Standards

IRO-006-4, and associated Attachment 1, should be retired when IRO-006-5 and IRO-006-EI-1 become effective.

The Regional Differences within IRO-006-4 should be retired when IRO-006-5 and IRO-006-EI-1 become effective.

Compliance with Standards

Once the standards become effective, the responsible entities identified in the applicability section of the standards must comply with the requirements. These include:

- Reliability Coordinators
- Balancing Authorities

Proposed Effective Date

The standards will become effective on the first day of the first calendar quarter after the date the standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standards becomes effective on the first day of the first calendar quarter after the date the standards are approved by the NERC Board of Trustees.

Exhibit D

Standard Drafting Team Roster

Transmission Loading Relief (TLR) Drafting Team (Project 2006-08)

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NERC Staff Coordinator	Andrew J. Rodriquez Manager of Business Practice Coordination	North American Electric Reliability Corporation 1120 G Street, N.W. Suite 990 Washington, D.C. 20005-3801	(202) 393-3998 (202) 393-3955 Fx andy.rodriquez@ nerc.net

Exhibit E

Record of Development of Proposed Reliability Standards

When completed, email to: gerry.cauley@nerc.net

Standard Authorization Request Form

Title of Proposed Standard **Reliability Coordination — Transmission Loading Relief IRO-006-0**	
Request Date	07/14/05

SAR Requestor Information	**SAR Type** (Put an 'x' in front of one of these selections)	
Name Roger Harszy - Chairman Operating Reliability Subcommittee	☐	New Standard
Primary Contact Roger Harszy	☒	Revision to existing Standard
Telephone (317) 249-5400 Fax (317) 249-5910	☐	Withdrawal of existing Standard
E-mail rharszy@midwestiso.org	☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

In August 2004, NERC and NAESB agreed to immediately begin a joint effort to update the Eastern Interconnection TLR Procedure, as reflected in Attachment 1 to reliability standard IRO-006-0, to divide the reliability requirements and business practices, and to incorporate other necessary improvements to the TLR procedure. In December 2004 NERC and NAESB formed the joint TLR Subcommittee to clarify and focus Attachment 1 to NERC reliability standard IRO-006-0 on the TLR requirements that are necessary for reliability, as distinguished from those TLR requirements that are business practices.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies by double clicking the grey boxes.)*		
☒	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☐	Planning Authority	Plans the bulk electric system
☐	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
☐	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☒	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☒	Transmission Owner	Owns transmission facilities
☒	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☒	Generator Owner	Owns and maintains generation unit(s)
☒	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☒	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☒	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☒	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check boxes for all that apply by double clicking the grey boxes.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.) NERC and NAESB formed the joint TLR Subommittee with the charge to review Attachment 1 (Transmission Loading Relief Procedure — Eastern Interconnection) of IRO-006-0 (Reliability Coordination — Transmission Loading Relief), and to identify each reliability requirement and business practice embedded within the the TLR procedure. The joint NERC/NAESB TLR Subcommittee completed its charge on June 1, 2005, when the subcommittee approved a revised Attachment 1 to IRO-006-0 and a revision to the NAESB TLR business practices. The revised TLR reliability standards, (i.e. Attachment 1), are attached to this Standards Authorization Request. During the course of the TLR subcommittee's effort to separate Attachment 1 into reliability standards under NERC's purview and business practices under NAESB's purview, the subcommittee developed a matric, which identified the disposition of each paragraph in the existing Attachment 1. That matrix is also attached to this Standards Authorization Request. This reliability standards development effort will begin by assessing for completeness and accuracy the revised Attachment 1 developed by the TLR Subcommittee using the subcommittee's matrix as a guide.. The end state of this standard development effort is a revised Attachment 1 to reliability standard IRO-006-0.

Related Standards

Standard No.	Explanation
IRO-006-0	Attachment 1 (TLR Procedure) to be replaced by a similar document addressing only the reliability elements of the TLR Procedure.
IRO-006-0	The urgent action revision to Attachment 1 that addressed the holding of dynamic schedules during TLR Level 1-4 will be incorporated into the NAESB TLR business practices.

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	Explanation

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
Email:		
NERC Region		**Registered Ballot Body Segment**
☐ ERCOT	☐	1 - Transmission Owners
☐ ECAR	☐	2 - RTOs, ISOs, Regional Reliability Councils
☐ FRCC	☐	3 - Load-serving Entities
☐ MAAC	☐	4 - Transmission-dependent Utilities
☐ MAIN	☐	5 - Electric Generators
☐ MAPP	☐	6 - Electricity Brokers, Aggregators, and Marketers
☐ NPCC	☐	7 - Large Electricity End Users
☐ SERC	☐	8 - Small Electricity End Users
☐ SPP	☐	9 - Federal, State, Provincial Regulatory or other Government Entities
☐ WECC		
☐ NA - Not Applicable		

Group Comments (Complete this page if comments are from a group.)	
Group Name:	Operating Reliability Working Group (ORWG)
Lead Contact:	**Robert Rhodes**
Contact Organization:	**Southwest Power Pool**
Contact Segment:	**2**
Contact Telephone:	**501-614-3241**
Contact Email:	**rrhodes@spp.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Dan Boezio	**AEP**	**SPP**	**1**
Bob Cochran	**SPS**	**SPP**	**1**
MIke Crouch	**WFEC**	**SPP**	**1**
Todd Fridley	**KCP&L**	**SPP**	**1**
Mike Gammon	**KCP&L**	**SPP**	**1**
Serhly Kotsan	**Boston Pacific**		
Robert Rhodes	**SPP**	**SPP**	**2**

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Background Information:

In August 2004, NERC and NAESB agreed to immediately begin a joint effort to update the Eastern Interconnection TLR Procedure, as reflected in Attachment 1 to reliability standard IRO-006-0, to divide the reliability requirements and business practices, and to incorporate other necessary improvements to the TLR procedure. In December 2004 NERC and NAESB formed the joint TLR Subcommittee to clarify and focus Attachment 1 to NERC reliability standard IRO-006-0 on the TLR requirements that are necessary for reliability, as distinguished from those TLR requirements that are business practices.

The subject SAR is required to revise Attachment 1 (Transmission Loading Relief Procedure — Eastern Interconnection) of IRO-006-0 (Reliability Coordination — Transmission Loading Relief) in accordance with the final work products of the NERC/NAESB TLR Subcommittee. NERC representatives to the TLR Subcommittee included members of the IDC Working Group, the Distribution Factors Working Group, the Reliability Coordinator Working Group, the Operating Reliability Subcommittee, the Operating Committee, and NERC staff.

Please review the SAR, as well as the additional information related to the SAR, posted on the NERC website and complete this Comment Form to provide feedback to the requestor on the proposed standards.

1. **Do you believe there is a reliability need for this proposed standard change? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

2. **Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: We feel that the division between business practices and reliability standards may not have gone far enough. The reliability standards should focus on establishing the criteria for initiation of different TLR levels and the required timeframes for relief. Business practices should focus on how the curtailments are executed to achieve the relief levels in the timeframes required by the reliability standard.

3. **Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: Everything in the proposed Attachment 1 - IRO-006-0 from Section 3 to the end of Attachment 1, including Appendices A and B, should be removed from the reliability standard and incorporated into the TLR Business Practices document. This material gets into the internal workings of the tool itself rather than dealing with the overall guiding principle of providing, and maintaining, relief within a specific timeframe.

4. **Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: Sections 3.2.1, 3.2.1.1 and 3.2.1.2 should be moved to the reliability standard since they deal more with how and why a Level 2 TLR is initiated than with the internal workings of the IDC.

5. Do you have any other comments on these proposed changes?

☒ Yes
☐ No

Comments: Section 1.5.1 of Attachment 1 refers to treatment of Interchange Transactions not in the IDC in accordance with NAESB business practices, but we could not find any reference to this treatment in the TLR business practices.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Dan Rochester	
Organization:	Independent Electricity System Operator (IESO), Ontario	
Telephone:	(905) 855-6363	
Email:	Dan.Rochester@ieso.ca	
NERC Region		**Registered Ballot Body Segment**
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact Email:

Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

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Please review the SAR, as well as the additional information related to the SAR, posted on the NERC website and complete this Comment Form to provide feedback to the requestor on the proposed standards.

1. **Do you believe there is a reliability need for this proposed standard change? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: We do not feel there is a reliability need for the proposed standard "change". We would contend that the change provides confusion to a very important reliability process. In order to understand the process the standard and the business practice are necessary.

2. **Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: The reliability and business practices within the TLR process are integrated to such an extent that the details need to remain contained within a single document for clarity. Concerns regarding the ability to effectively manage the model and the process with the current proposed split need to be addressed. The ability to follow developing market issues must also be retained. Steps 1.4.1, 1.4.1.1, 1.5, 1.5.1, 1.6, 1.7, 2.1.2, 2.2.2, 2.4.2, 2.5.2, 3.2.1.2, 3.3.1.2, 7.1, are reliability related and should remain in the standard. The dynamic schedule part of of 1.6.6 was added to the Standard in June of this year with approval of 100% of the ballot body. It should remain as part of this standard.

3. **Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments:

4. **Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments: See comments in question 2.

5. **Do you have any other comments on these proposed changes?**

   ☒ Yes

☐ No

Comments: The IESO does not fully support the modifications proposed in this SAR. The proposed change provides confusion to a very important reliability process. Also the proposed standard references a NAESB standard which is inconsistent with the NERC Standards Process Manual which says "All mandatory requirements of a reliability standard shall be within an element of the standard. Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself." There are mandatory parts of the proposed standard in the NAESB business practice that are necessary for the successful implementation of this reliability standard. With the two documents being modified by separate entities there is a good chance that the documents will not be coordinated and kept in synchronization when changes are made. As acknowledged by the TLR Subcommittee that worked to create this proposed split, the business practices and reliability aspects of TLR are very intertwined. In effect, the information in both the proposed NERC and NAESB standard must be simultaneously available to the Operators in the Control Room, in order for them to operate the system reliably. While the effort to create this initial split in the TLR standards has been completed, consideration should be given as to how this split will be maintained, if going forward, before it is adopted by the industry. Operator training issues, as well as the ownership and funding of the IDC tool should be considered in this evaluation before such a significant step is taken on a standard that is fundamental to the reliability of the Eastern Interconnection. This is an important process that requires a complete understanding of the impact of separating the business practice from the reliability concepts. It is not clear that the current proposed document split will retain the integrity of the TLR process. The potential negative impact of degrading the RC's ability to manage loop flow dictates that any change in documentation and responsibility must proceed carefully.

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☐ **NA - Not Applicable**		

Group Comments (Complete this page if comments are from a group.)

Group Name: Southern Company Generation

Lead Contact: **Roman Carter**

Contact Organization: **Regulatory Affairs**

Contact Segment: **6**

Contact Telephone: **205.257.6027**

Contact Email: **jrcarter@southernco.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Joel Dison	**Southern Company Generation**	**SERC**	**6**
Clifford Shepard	**Southern Company Generation**	**SERC**	**6**
Lucius Burris	**SouthernCompanyGeneration**	**SERC**	**6**
Steve Lowe	**Southern Company Generation**	**SERC**	**6**

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1. **Do you believe there is a reliability need for this proposed standard change? If not, please explain in the comment area.**

   ☒ Yes
   ☐ No
   Comments:

2. **Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.**

   ☒ Yes
   ☐ No
   Comments:

3. **Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.**

   ☐ Yes
   ☒ No
   Comments:

4. **Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.**

   ☐ Yes
   ☒ No
   Comments:

5. **Do you have any other comments on these proposed changes?**

   ☒ Yes
   ☐ No
   Comments: As NAESB and NERC standards are approved and implemented which require close coordination between the two organizations, the need for a common "Operations Manual" may become necessary for System Operators.

This Operations Manual should provide real time standard requirements applicable to the System Operators on NERC and NAESB standards related to their daily decision-making authority. This SAR for TLR is a potential standard that would fit the type of requirements that should be contained in the Manual.

As future changes to the requirements of standards contained in the Manual occur within either NERC or NAESB, coordination between the two organizations will be very important to ensure changes to the complementary standard within the other organization is implemented.

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Group Comments (Complete this page if comments are from a group.)

Group Name: CP9 Reliability Standards Working Group

Lead Contact: **Guy Zito**

Contact Organization: **Northeast Power Coordinating Council**

Contact Segment: **2**

Contact Telephone: **212-840-1070**

Contact Email: **gzito@npcc.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Kathleen Goodman	**ISO New England**	**NPCC**	**2**
Khaqan Khan	**The IEMO, Ontario**	**NPCC**	**2**
Vinod (Bob) Kotecha	**ConEd**	**NPCC**	**1**

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Please review the SAR, as well as the additional information related to the SAR, posted on the NERC website and complete this Comment Form to provide feedback to the requestor on the proposed standards.

1. Do you believe there is a reliability need for this proposed standard change? If not, please explain in the comment area.

☐ Yes

☒ No

Comments: This proposed standard change was not initiated due to reliability needs. NPCC Participating members believe that the change is in conflict to very important reliability rules. In order to understand the process the standard and the business practice are necessary.

2. Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.

☐ Yes

☒ No

Comments:
- Section 2.6 and 2.7 in the original standard defined step-by-step actions the Operator is to take under TLR Levels 5a and 5b. These actions have been removed and currently reside in the proposed NAESB standard. It is not appropriate for a business practice standard to define actions to be taken by a Reliability Coordinator in real-time operations to resolve a reliability issue.

The need for a TLR is in response to a problem with reliability on the system. The Operator must be presented with all the information that is contained in both the proposed NERC and NAESB standards in order to issue that TLR. If the operator does not know what transactions are available in any given category, they do not know what TLR level is needed to resolve the situation. NPCC participating members do not agree with the assertion that the information contained in the NAESB standard does not impact reliability.

Some aspects of the original IRO-006 are 'business practices,' and that the completed effort generally meets the original intent of splitting the business practice and reliability components. However, seeing the resulting split, it is clear that these business practices have a direct impact on reliability and they should be maintained within one single standard to prevent confusion and conflicts. Also, since the fundamental practice for defining the priorities and treatment of transactions under each TLR level is consistent with the FERC pro-forma tariff, there is minimal subjectivity involved in the business practices that are included in the original NERC standard.

Steps 1.4.1, 1.4.1.1, 1.5, 1.5.1, 1.6, 1.7, 2.1.2, 2.2.2, 2.4.2, 2.5.2, 3.2.1.2, 3.3.1.2, 7.1, are reliability related and should remain in the standard. The dynamic schedule part of of 1.6.6 was added to the Standard in June of this year with 100% of the ballot body approval, it should remain as part of this standard.

3. Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.

☐ Yes

☒ No

Comments: See response to question 2.

4. Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.

☒ Yes

☐ No

Comments: See response to question 2.

5. Do you have any other comments on these proposed changes?

☒ Yes

☐ No

Comments:

This is an important process that requires a complete understanding of the impact of separating the business practice from the reliability concepts. It is not clear that the current proposed document split will retain the integrity of the TLR process. The potential negative impact of degrading the RC's ability to manage loop flow dictates that any change in documentation and responsibility must proceed carefully. NPCC participating Members believe the propsed change provides confusion to a very important reliability process. There are manditory parts of the proposed standard in the NAESB business practice that are necessary for the successful implementation of this reliability standard. With the two documents being modified by separate entities there is a good chance that the documents will not be coordinated and kept in syncronization when changes are made.

Recommend restoring the reference to RCIS tool in 1.4. That reference was eliminated when the old 1.4.1 was removed.

- The old 1.5.1 was removed. There's a general statement added to 1.2 that says "In addition, a Reliability Coordinator may implement other NERC-approved procedures to request relief to mitigate any other transmission constraints as necessary to preserve the reliability of the system." But, that phrase does not seem to capture the same intent as the previous 1.5.1 wording.

- Section 1.5.3 the numbering on this section is very confusing. Suggest the following:

1.5.3.1. Causes of questionable IDC results may include: (1) Missing Interchange transactions that are known to contribute to the Constraint, (2) Significant change in transmission system topology, or (3) TDF matrix error.

1.5.3.2 Impacts of questionable IDC results may include: (1) relief that would have no effect on, or aggravate the constraint or (2) that would initiate a constraint elsewhere.

1.5.3.3. If other Reliability Coordinators are involved in the TLR event, all impacted Reliability Coordinators shall be in agreement before any adjustments to the relief request list are made.

- Title of Section 2 should be changed to be only "Transmission Loading Relief (TLR) Levels."

- Section 3 is missing section 3.1.

- Suggest that Section 3.2 include a reference to the fact that transactions submitted after the XX:25 deadline will put on HOLD.

- Are Section 3.3.3 and Section 3.4.3 referring back to the deadline defined in 3.2? If so, that section should be referenced.

- Text in 3.3.1.1 and 3.3.2 are referring to the same process for reallocation and should use the same terminology. Suggest 3.3.1.1 text be changed to "At XX:25 a reallocation will be performed for the following hour to maintain the target flow identified for the current hour".

- Text in 3.4.1.1 and 3.4.2 are referring to the same process for reallocation and should use the same terminology. Suggest 3.4.1.1 text be changed to "At XX:25 a reallocation will be performed for the following hour to maintain the target flow identified for the current hour".

- The section notation of Appendix B should be modified. The Section numbering shown in the index is not how the headings are titled in the Sections. Also, Section F and Section G should not be 5.1 and 5.2; they should be at the highest index level.

General Comment: There have been changes to the congestion management process over the last few years that involve the use of Market information by the IDC. Any new standards addressing the TLR process and the IDC, whether in NERC or NAESB, should consider addressing the current information available to the IDC and include some mention of that information in that standard development. In addition, Operator training issues, as well as the ownership and funding of the IDC tool should be considered in this evaluation before such a significant step is taken on a standard that is fundamental to the reliability of the Eastern Interconnection.

General Comment: One other practical concern that has not been addressed is the ownership, impact and funding of the IDC tool that automates the 'business practices' of implementing a TLR for the Operator. The split of the original NERC IRO-006 should not be adopted until this issue is addressed and resolved.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Scott R. Cunningham	
Organization:	Ohio Valley Electric Corporation	
Telephone:	740-289-7225	
Email:	scunning@ovec.com	
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1. **Do you believe there is a reliability need for this proposed standard change? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

2. **Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

3. **Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: At times, RTO ramp limitations are invoked when TLR curtailments occur. This issue is not covered in the standard, but seems to be related to a business practice, rather than a reliability issue. Perhaps the ramp limitation should be waived or adjusted if the limitation is caused by the curtailments that occur with the TLR.

4. **Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.**

☐ Yes

☒ No

Comments:

5. **Do you have any other comments on these proposed changes?**

☒ Yes

☐ No

Comments: The use of proxy flowgates is not mentioned at all in the proposed standard. The use of proxy flowgates should not be allowed, except in very unusual circumstances. If use of a proxy flowgate is necessary, such use should be justified and approval from all affected parties should be obtained.

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Email:		
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☐ SERC	☐	8 - Small Electricity End Users
☐ SPP	☐	9 - Federal, State, Provincial Regulatory or other Government Entities
☐ WECC		
☐ NA - Not Applicable		

Group Comments (Complete this page if comments are from a group.)

Group Name: Public Service Commission of South Carolina

Lead Contact: **Phil Riley**

Contact Organization: **Public Service Commission of South Carolina**

Contact Segment: **9**

Contact Telephone: **803-896-5154**

Contact Email: **philip.riley@psc.sc.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
John E. Howard	Public Service Commission of SC	SERC	9
David A. Wright	Public Service Commission of SC	SERC	9
Randy Mitchell	Public Service Commission of SC	SERC	9
Elizabeth B. Fleming	Public Service Commission of SC	SERC	9
G. O'Neal Hamilton	Public Service Commission of SC	SERC	9
Mignon L. Clyburn	Public Service Commission of SC	SERC	9
C. Robert Moseley	Public Service Commission of SC	SERC	9

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   ☒ Yes
   ☐ No
   Comments:

2. **Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.**

   ☒ Yes
   ☐ No
   Comments:

3. **Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.**

   ☐ Yes
   ☒ No
   Comments:

4. **Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.**

   ☐ Yes
   ☒ No
   Comments:

5. **Do you have any other comments on these proposed changes?**

   ☐ Yes
   ☒ No
   Comments:

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Organization:		
Telephone:		
Email:		
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☐ **WECC**		
☐ **NA - Not Applicable**		

Group Comments (Complete this page if comments are from a group.)

Group Name: Medwest Reliability Organization

Lead Contact: **Alan Boesch**

Contact Organization: **Medwest Reliability Organization**

Contact Segment: **2**

Contact Telephone: **402-845-5210**

Contact Email: **agboesc@nppd.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Terry Bilke	**MISO**	**MRO**	**2**
Robert Coish	**MHEB**	**MRO**	**2**
Dennis Florom	**LES**	**MRO**	**2**
Todd Gosnell	**OPPD**	**MRO**	**2**
Wayne Guttormson	**SPC**	**MRO**	**2**
Jim Maenner	**WPS**	**MRO**	**2**
Tom Mielnik	**MEC**	**MRO**	**2**
Darrick Moe	**WAPA**	**MRO**	**2**
Ken Goldsmith	**ALT**	**MRO**	**2**
Joe Knight	**MRO**	**MRO**	**2**
The 31 Additional MRO Member	**Companies not named above**	**MRO**	**2**

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1. **Do you believe there is a reliability need for this proposed standard change? If not, please explain in the comment area.**

   ☐ Yes
   ☒ No

   Comments: The MRO does not believe there is a reliability need for the proposed standard change. We would contend that the change provides confusion to a very important reliability process. In order to understand the process the standard and the business practice are necessary.

2. **Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: Steps 1.4.1, 1.4.1.1, 1.5, 1.5.1, 1.6, 1.7, 2.1.2, 2.2.2, 2.4.2, 2.5.2, 3.2.1.2, 3.3.1.2, 7.1, are reliability related and should remain in the standard. The dynamic schedule part of of 1.6.6 was added to the Standard in June of this year with 100% of the ballot body approval, it should remain as part of this standard.

3. **Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments:

4. **Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments: See comments in question 2.

5. **Do you have any other comments on these proposed changes?**

   ☒ Yes
   ☐ No

Comments: It was very difficult to review the changes to the standard without a redline copy. In order to perform our review we made a redline of the original standard. The MRO does not support this modification. The propsed change provides confusion to a very important reliability process. Also the proposed standard references a NAESB standard which is inconsistent with the NERC Standards Process Manual which says "All mandatory requirements of a reliability standard shall be within an element of the standard. Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself." There are manditory parts of the proposed standard in the NAESB business practice and are necessary for the successful implementation of this reliability standard. With the two documents being modified by separate entities there is a good chance that the documents will not be coordinated and kept in syncronization when changes are made.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Raj Rana - Coordinator	
Organization:	AEP	
Telephone:	614-716-2359	
Email:	raj_rana@AEP.com	
NERC Region		**Registered Ballot Body Segment**
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☒ ECAR	☐	2 - RTOs, ISOs, Regional Reliability Councils
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact Email:

Additional Member Name	Additional Member Organization	Region*	Segment*

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1. **Do you believe there is a reliability need for this proposed standard change? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: We support the NERC/NAESB initiative to split the TLR document in order extract the business practice aspects. However, there is no reliability need for this proposed standard change. The reliability need in terms by managing power flow relief in a pre-defined time period in order to maintain security of the system did not change. However, this draft does not provide reliability performance specifications, such as X MW or % of relief in Y minutes. The NERC portion of this standard should specify what is neeed to maintain the system security in the interconnected environment, while the NAESB portion should specify the road map as to how to do it.

2. **Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: The two documents are overlapping. Same statements in both documents.

3. **Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments: We believe that items like firm/non-firm transactions types, TLR levels etc. should be taken out of the reliability portion of this standard. These items should be inlcuded in the NAESB portion. The reliability portion should only address the needed relief amount on constratined facilities and the time under which the relief should be provided in order to maintain security of the interconnected network.

4. **Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.**

   ☐ Yes

   ☐ No

   Comments: No comments.The TLR business practices document is not available.

5. **Do you have any other comments on these proposed changes?**

☒ Yes

☐ No

Comments: Use of proxy flowgates by the reliabiliy coordinators must be prohibited. This practice must be explicitely addressed in this standard because, the use of proxy flowgates not onlly will result in mis-allocation of corrective actions, but at worst could even result in actions being taken that actually increase flows on the limiting element, instead of decreasing them.

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☐ WECC		
☐ NA - Not Applicable		

Group Comments (Complete this page if comments are from a group.)

Group Name: Joint Interchange Scheduling Working Group

Lead Contact: **Bert Gumm**

Contact Organization: **NAESB/NERC**

Contact Segment: **1**

Contact Telephone: **208-388-5147**

Contact Email: **rgumm@idahopower.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Troy Simpson	Bonneville Power Administration	WECC	1
Marilyn Franz	Sierra Pacific Power Company	WECC	1
Jim Hansen	Seattle City Light	WECC	1
Bert Gumm	Idaho Power Company	WECC	1
Kathee Downing	PacifiCorp	WECC	1
Jim Eckelcamp	Progress Energy	SERC	6
Bob Harshbarger	Puget Sound Energy	WECC	1
Paul Sorenson	OATI	N/A	
Bob Schwermann	Sacremento Municipal Utilities D	WECC	1
Bonita Smulski	Bonneville Power Admin	WECC	1
Taryn McPherson	Bonneville Power Admin	WECC	1
Salah Kitali	Bonneville Power Admin	WECC	1
Joel Mickey	ERCOT	ERCOT	2
Andrew Burke	PacifiCorp	WECC	1

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☒ Yes

☐ No

Comments:

2. **Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

3. **Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.**

☐ Yes

☒ No

Comments:

4. **Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.**

☐ Yes

☒ No

Comments:

5. **Do you have any other comments on these proposed changes?**

☒ Yes

☐ No

Comments: 1. We request that the scope of this SAR be expanded to include resolving the reloading of curtailed transactions above their reliability limit by an entity other than the initiating entity or above any pre-existing reliability or market profiles. 2. We also request that the scope of the SAR be expanded to include standards for when curtailments may be denied and when curtailments may be issued. 1 - There have been several instances where a curtailment has been issued and then been automatically or manually reloaded above the reliability limit. The automatic reload problem created by the IDC has been resolved by CO-148, automatic reload by other back office applications has not been corrected, nor have manual adjustments. There are several options available for correcting this problem. This should be addressed by specifying requirements and performance measures in the TLR standard and may also be addressed through NAESB business practices and modifcations to the e-Tag specification. Also, any pre-existing curtailment levels are lost. JISWG recommends that the entity who has issued the curtailment be the only entity able to authorize the reload. When the reload occurs the energy profile should be limited to the next lowest reliability limit or market adjustment profile. 2- Under normal circumstances, a curtailment (issued for reliability reasons) should not be denied. However, there are some limited circumstances where a curtailment should be denied. For example, if a curtailment comes in and the generator cannot meet the ramp requirements, then the curtailment could be denied and would be reissued for the next scheduling interval. This ensures that the tags reflect actual conditions. In other cases, curtailments are sometimes issued when PSE's cannot make their market level adjustments prior to cutoff. The TLR standard should address those specific reasons for denying a curtailment. Reliability is compromised when curtailments are denied for non-reliability reasons. Reliability may also be compromised when curtailments are issued for non-reliability reasons. If scope of the SAR is adjusted, JISWG volunteers to assist the drafting team with providing specific language for the TLR standard addressing these issues.

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Group Comments (Complete this page if comments are from a group.)

Group Name: Entergy Services - Transmission

Lead Contact: **Ed Davis**

Contact Organization: **Entergy Services - Transmission**

Contact Segment: **1**

Contact Telephone: **504-310-5884**

Contact Email: **edavis@entergy.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Rick Riley	**Entergy Services**		**1**
Jay Zimmerman	**Entergy Services**		**1**
George Bartlett	**Entergy Services**		**1**
James Case	**Entergy Services**		**1**
Bill Aycock	**Entergy Services**		**1**
Melinda Montgomery	**Entergy Services**		**1**
Narinder Saini	**Entergy Services**		**1**
Maurice Casadaban	**Entergy Services**		**1**

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   ☐ Yes

   ☒ No

   Comments:

   The interplay between the business practices and reliability practices associated with TLR is so intimate that the two should not be divided into two standards practices. It would be best for the industry that one TLR standard be developed by the two organizations.

2. **Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments:

   A complete response to this question is inappropriate at this time.

   It appears that IRO-006 will be divided into 3 major documents: NERC TLR reliability standards, NAESB business practices, and the IDC Reference Documentation. The answer to this question will require a detailed comparison of all three documents with respect to the existing IRO-006. We do not have the NAESB document in front of us in order to make that detailed comparison. In addition, it does not appear that a detailed comparison of the three documents has been requested since the SAR request states in the last paragraph that the development effort will begin by assessing for completeness and accuracy the revised Attachement 1.

3. **Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

   The NERC TLR reliability standard part of this documentation appears to be all reliability related. However, the IDC Reference Document appears to have significant business practice elements contained in it.

4. **Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.**

   ☐ Yes

☒ No

Comments:

We can not answer this question since we do not have the NAESB proposed TLR business practices in this package.

5. **Do you have any other comments on these proposed changes?**

☒ Yes

☐ No

Comments:

The SAR contains the statement that the urgent action revision to Attachemnt 1 addressing dynamic schedules will be incorporated into the NAESB business practices. We suggest starting with IRO-006-1, rather than with IRO-006-0.

Please delete all references to IRO-006-0 (and IRO-006-1) in headers, footers, titles, etc. This new document will result in a new version of IRO--006. This current draft is not version 0 or 1.

Please delete all references to adoption by the NERC Board of Trustees, Effective Date, and all dates because the document we are viewing has not been adopted by the BOT and does not have an Effective Date.

Please provide a redline version showing the draft changes to IRO-006-1. This redline would make review and comment much easier for commentors.

We appreciate the development of the matrix and would probably find it useful for keeping track of the disposition of each requirement in the original IRO-006. However, in its current form we do not understand which columns relate to which documents and the row designations are not clearly understood.

This form is to be used to submit comments on the proposed Draft 1 of the Proposed Reliability Coordination- Transmission Loading Relief SAR. Comments must be submitted by **September 2, 2005**. You may submit the completed form by emailing it to: sarcomm@nerc.com with the words "Reliability Coordination- Transmission Loading Relief SAR" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

ALL DATA ON THIS FORM WILL BE TRANSFERRED AUTOMATICALLY TO A DATABASE AND IT IS THEREFORE IMPORTANT TO ADHERE TO THE FOLLOWING REQUIREMENTS:

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Do submit any formatted text or markups in a separate WORD file.

DO NOT: **Do not** insert tabs or paragraph returns in any data field.
Do not use numbering or bullets in any data field.
Do not use quotation marks in any data field.
Do not submit a response in an unprotected copy of this form.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Cheryl Mendrala	
Organization:	ISO New England	
Telephone:	413 535-4184	
Email:	cmendrala@iso-ne.com	

NERC Region		Registered Ballot Body Segment
☐ ERCOT	☐	1 - Transmission Owners
☐ ECAR	☒	2 - RTOs, ISOs, Regional Reliability Councils
☐ FRCC	☐	3 - Load-serving Entities
☐ MAAC	☐	4 - Transmission-dependent Utilities
☐ MAIN	☐	5 - Electric Generators
☐ MAPP	☐	6 - Electricity Brokers, Aggregators, and Marketers
☒ NPCC	☐	7 - Large Electricity End Users
☐ SERC	☐	8 - Small Electricity End Users
☐ SPP	☐	9 - Federal, State, Provincial Regulatory or other Government Entities
☐ WECC		
☐ NA - Not Applicable		

Group Comments (Complete this page if comments are from a group.) **Group Name:** **Lead Contact:** **Contact Organization:** **Contact Segment:** **Contact Telephone:** **Contact Email:**			
Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

*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:

In August 2004, NERC and NAESB agreed to immediately begin a joint effort to update the Eastern Interconnection TLR Procedure, as reflected in Attachment 1 to reliability standard IRO-006-0, to divide the reliability requirements and business practices, and to incorporate other necessary improvements to the TLR procedure. In December 2004 NERC and NAESB formed the joint TLR Subcommittee to clarify and focus Attachment 1 to NERC reliability standard IRO-006-0 on the TLR requirements that are necessary for reliability, as distinguished from those TLR requirements that are business practices.

The subject SAR is required to revise Attachment 1 (Transmission Loading Relief Procedure — Eastern Interconnection) of IRO-006-0 (Reliability Coordination — Transmission Loading Relief) in accordance with the final work products of the NERC/NAESB TLR Subcommittee. NERC representatives to the TLR Subcommittee included members of the IDC Working Group, the Distribution Factors Working Group, the Reliability Coordinator Working Group, the Operating Reliability Subcommittee, the Operating Committee, and NERC staff.

Please review the SAR, as well as the additional information related to the SAR, posted on the NERC website and complete this Comment Form to provide feedback to the requestor on the proposed standards.

1. **Do you believe there is a reliability need for this proposed standard change? If not, please explain in the comment area.**

☐ Yes
☒ No

Comments: This proposed standard change was not initiated due to reliability needs.

2. **Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.**

☐ Yes

☒ No

Comments:
- Section 2.6 and 2.7 in the original standard defined step-by-step actions the Operator is to take under TLR Levels 5a and 5b. These actions have been removed and currently reside in the proposed NAESB standard. It is not appropriate for a business practice standard to define actions to be taken by a Reliability Coordinator in real-time operations to resolve a reliability issue.

The need for a TLR is in response to a problem with reliability on the system. There is no doubt that the Operator must be presented with all the information that is contained in both the proposed NERC and NAESB standards in order to issue that TLR. If the operator does not know what transactions are available in any given category, they do not know what TLR level is needed to resolve the situation. Therefore, we cannot agree with the assertion that the information contained in the NAESB standard does not impact reliability.

We agree that some aspects of the original IRO-006 are 'business practices,' and agree that the completed effort generally meets the original intent of splitting the business practice and reliability components. However, seeing the resulting split, it is clear that these business practices have a direct impact on reliability and we believe they should be maintained within one single standard to prevent confusion and conflicts. Also, since the fundamental practice for defining the priorities and treatment of transactions under each TLR level is consistent with the FERC pro-forma tariff, there is minimal subjectivity involved in the business practices that are included in the original NERC standard.

3. **Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: See response to question 2.

4. **Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: See response to question 2.

5. **Do you have any other comments on these proposed changes?**

☒ Yes

☐ No

Comments:

- Recommend restoring the reference to RCIS tool in 1.4. That reference was eliminated when the old 1.4.1 was removed.

- The old 1.5.1 was removed. There's a general statement added to 1.2 that says "In addition, a Reliability Coordinator may implement other NERC-approved procedures to request relief to mitigate any other transmission constraints as necessary to preserve the reliability of the system." But, that phrase does not seem to capture the same intent as the previous 1.5.1 wording.

- Section 1.5.3 the numbering on this section is very confusing. Suggest the following:

1.5.3.1. Causes of questionable IDC results may include: (1) Missing Interchange transactions that are known to contribute to the Constraint, (2) Significant change in transmission system topology, or (3) TDF matrix error.

1.5.3.2 Impacts of questionable IDC results may include: (1) relief that would have no effect on, or aggravate the constraint or (2) that would initiate a constraint elsewhere.

1.5.3.3. If other Reliability Coordinators are involved in the TLR event, all impacted Reliability Coordinators shall be in agreement before any adjustments to the relief request list are made.

- Title of Section 2 should be changed to be only "Transmission Loading Relief (TLR) Levels."

- Section 3 is missing section 3.1.

- Suggest that Section 3.2 include a reference to the fact that transactions submitted after the XX:25 deadline will put on HOLD.

- Are Section 3.3.3 and Section 3.4.3 referring back to the deadline defined in 3.2? If so, that section should be referenced.

- Text in 3.3.1.1 and 3.3.2 are referring to the same process for reallocation and should use the same terminology. Suggest 3.3.1.1 text be changed to "At XX:25 a reallocation will be performed for the following hour to maintain the target flow identified for the current hour".

- Text in 3.4.1.1 and 3.4.2 are referring to the same process for reallocation and should use the same terminology. Suggest 3.4.1.1 text be changed to "At XX:25 a reallocation will be performed for the following hour to maintain the target flow identified for the current hour".

- The section notation of Appendix B should be modified. The Section numbering shown in the index is not how the headings are titled in the Sections. Also, Section F and Section G should not be 5.1 and 5.2; they should be at the highest index level.

General Comment: There have been changes to the congestion management process over the last few years that involve the use of Market information by the IDC. Any new standards addressing the TLR process and the IDC, whether in NERC or NAESB, should consider addressing the current information available to the IDC and include some mention of that information in that standard development.

General Comment: One other practical concern that has not been addressed is the ownership, impact and funding of the IDC tool that automates the 'business practices' of implementing a TLR for the Operator. The split of the original NERC IRO-006 should not be adopted until this issue is addressed and resolved.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
Email:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 - Transmission Owners
☐ **ECAR**	☐	2 - RTOs, ISOs, Regional Reliability Councils
☐ **FRCC**	☐	3 - Load-serving Entities
☐ **MAAC**	☐	4 - Transmission-dependent Utilities
☐ **MAIN**	☐	5 - Electric Generators
☐ **MAPP**	☐	6 - Electricity Brokers, Aggregators, and Marketers
☐ **NPCC**	☐	7 - Large Electricity End Users
☐ **SERC**	☐	8 - Small Electricity End Users
☐ **SPP**	☐	9 - Federal, State, Provincial Regulatory or other Government Entities
☐ **WECC**		
☐ **NA - Not Applicable**		

Group Comments (Complete this page if comments are from a group.)

Group Name: Southern Company - Transmission

Lead Contact: **Jim Busbin**

Contact Organization: **Southern Company Services**

Contact Segment: **1**

Contact Telephone: **205-257-6357**

Contact Email: **jybusbin@southernco.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Marc Butts	**Southern Company Services**	**SERC**	**1**
Jim Viikinsalo	**Southern Company Services**	**SERC**	**1**

*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:

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The subject SAR is required to revise Attachment 1 (Transmission Loading Relief Procedure — Eastern Interconnection) of IRO-006-0 (Reliability Coordination — Transmission Loading Relief) in accordance with the final work products of the NERC/NAESB TLR Subcommittee. NERC representatives to the TLR Subcommittee included members of the IDC Working Group, the Distribution Factors Working Group, the Reliability Coordinator Working Group, the Operating Reliability Subcommittee, the Operating Committee, and NERC staff.

Please review the SAR, as well as the additional information related to the SAR, posted on the NERC website and complete this Comment Form to provide feedback to the requestor on the proposed standards.

1. **Do you believe there is a reliability need for this proposed standard change? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: N/A

2. **Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: N/A

3. **Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: N/A

4. **Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: N/A

5. **Do you have any other comments on these proposed changes?**

☒ Yes

☐ No

Comments: My only concern with the splitting of reliability requirements and business practices is how they will be managed and/or coordinated in the future. I'm not sure what value is added to the reliability of the grid by now having our grid operators manage their respective systems with a NERC manual in one hand and a NAESB manual in the other. Right now the two documents are in synch with one another; however, as we move forward in time, what will be the process for conflict resolution between the two?

Background:

The TLR – General Update SAR drafting team thanks all commenters who submitted comments on the first draft of the SAR and associated proposed revisions to IRO-006. The SAR was posted from August 4 through September 2, 2005. The drafting team asked stakeholders to provide feedback on the SAR and standard through a special SAR Comment Form. There were 12 sets of comments, including comments representing the views of 65 different people from 36 different entities in seven of the eight NERC Regions.

When the first SAR was posted for comment, the requestor had envisioned publishing a NERC standard and an associated NAESB business practice. Many stakeholders indicated that this would be very challenging for use in real-time operations. In response to stakeholder concerns, NAESB and NERC developed and approved the NERC-NAESB Procedure for Joint Development and Coordination. This procedure guides joint development of standards and business practices when the reliability and business practice components are intricately entwined within a proposed standard. This procedure was approved for implementation by the Standards Committee, NERC Board of Trustees and the NAESB Board and is being used to make modifications to IRO-006.

Based on stakeholder comments and changes that have taken place in the industry since the initial posting of the SAR, the drafting team made the following significant changes to the SAR:

- Modified the desired product so that instead of publishing the NERC Reliability Standard as a separate product, will produce a single document with NAESB that includes both the NERC reliability requirements and the NAESB business practices relative to the TLR Procedure. This should satisfy commenters who indicated that having two different documents would be a detriment to reliability. (As envisioned, the NERC/NAESB split would be balloted as soon as possible.)
- Expanded the scope of the SAR to include consideration of **all** the modifications to the standard proposed by FERC and stakeholders as identified on the 'Standard Review Form' attached to the revised SAR. This expansion in scope should satisfy the need to improve the overall quality of this standard. The existing standard includes some material that is more appropriate in a technical reference, and some parts of the standard don't meet the quality criteria established for ERO standards. The expansion in scope brings this SAR into conformance with the *Reliability Standards Development Plan: 2007–2009.*
- Expanded the scope of the SAR to include consideration of modifications previously addressed in the SAR to Modify IRO-006 for Market Information. This should satisfy stakeholders who suggested that having multiple SARs for the same project is not desirable.

With the above conforming changes, the drafting team is recommending that the SAR move forward to standard drafting.

In this 'Consideration of Comments' document, stakeholder comments have been organized so that it is easier to see the summary of changes in response to each question posed by the requestor. All comments received on the can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Reliability-Coordination-Transmission-Loading-Relief.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Cauley at 609-452-8060 or at gerry.cauley@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure Manual: http://www.nerc.com/standards/newstandardsprocess.html

Commenter	Organization	Industry Segment								
		1	2	3	4	5	6	7	8	9
Dan Boezio (G1)	AEP	x								
Raj Rana	AEP	x		x		x				
Ken Goldsmith (G5)	ALT									
Serhly Kotsan (G1)	Boston Pacific									
Bonita Smulski (G6)	BPA	x								
Salah Kitali (G6)	BPA	x								
Taryn McPherson (G6)	BPA	x								
Troy Simpson (G6)	BPA	x								
Vinod Kotecha (G3)	ConEd	x								
Bill Aycock (G7)	Entergy	x								
Ed Davis (G7)	Entergy	x								
George Bartlett (G7)	Entergy	x								
James Case (G7)	Entergy	x								
Jay Zimmerman (G7)	Entergy	x								
Maurice Casadaban (G7)	Entergy	x								
Melinda Montgomery (G7)	Entergy	x								
Narinder Saini (G7)	Entergy	x								
Rick Riley (G7)	Entergy	x								
Joel Mickey (G6)	ERCOT		x							
Bert Gumm (G6)	Idaho Power	x								
Dan Rochester	IESO		x							
Khaqan Khan (G3)	IESO		x							
Cheryl Mendrala	ISO New England		x							
Kathleen Goodman (G3)	ISO New England		x							
Mike Gammon (G1)	KCP&L	x								
Todd Fridley (G1)	KCP&L	x								
Dennis Florom (G5)	LES	x								

Tom Mielnik (G5)	MEC									
Robert Coish (G5)	MHEB	x		x	x	x				
Terry Bilke (G5)	MISO		x							
Joe Knight (G5)	MRO		x							
Guy Zito (G3)	NPCC		x							
Alan Boesch (G5)	NPPD									
Paul Sorenson (G6)	OATI									
Scott Cunningham	Ohio Valley Electric Corp		x	x	x	x	x	x	x	
Todd Gosnell (G5)	OPPD									
Andrew Burke (G6)	PacifiCorp	x								
Kathee Downing (G6)	PacifiCorp	x								
Jim Eckelcamp (G6)	Progress Energy						x			
C. Robert Moseley (G4)	PSC of South Carolina									**x**
David Wright (G4)	PSC of South Carolina									**x**
Elizabeth Fleming (G4)	PSC of South Carolina									**x**
G. O'Neal Hamilton (G4)	PSC of South Carolina									**x**
John Howard (G4)	PSC of South Carolina									**x**
Mignon Clyburn (G4)	PSC of South Carolina									**x**
Phil Riley (G4)	PSC of South Carolina									**x**
Randy Mitchell (G4)	PSC of South Carolina									**x**
Bob Harshbarger (G6)	Puget Sound Energy	x								
Jim Hansen (G6)	Seattle City Light	x								
Marilyn Franz (G6)	Sierra Pacific Power Co	x								
Bob Schwermann (G6)	SMUD	x								
Clifford Shephard (G2)	Southern Company Generation						x			
Joel Dison (G2)	Southern Company Generation						x			
Lucius Burris (G2)	Southern Company Generation						x			
Roman Carter (G2)	Southern Company Generation						x			
Steve Lowe (G2)	Southern Company Generation						x			

Jim Busbin (G8)	Southern Company Services	x								
Jim Viikinsalo (G8)	Southern Company Services	x								
Marc Butts (G8)	Southern Company Services	x								
Wayne Guttormson (G5)	SPC									
Robert Rhodes (G1)	SPP		x							
Bob Cochran (G1)	SPS	x								
Darrick Moe (G5)	WAPA									
Mike Crouch (G1)	WFEC	x								
Jim Maenner (G5)	WPS									

G1 – SPP Operating Reliability Working Group
G2 – Southern Company Generation
G3 – NPCC CP9 Reliability Standards Working Group
G4 – Public Service Commission of South Carolina
G5 – Midwest Reliability Organization
G6 – Joint Interchange Scheduling Working Group NERC/NAESB
G7 – Entergy
G8 – Southern Company Services

Index to questions, comments and responses:

1. Do you believe there is a reliability need for this proposed standard change? If not, please explain in the comment area.

Summary Consideration: While there was no overwhelming consensus on this issue, most commenters indicated there is a reliability-related need for the proposed standard change. Of the commenters who disagreed with the change, some felt that the change was not 'initiated' due to a reliability need and some felt that splitting the standard between NERC and NAESB would lead to confusion.
The original intent of the SAR was to publish both a NERC version of the standard and a NAESB version of the associated business practice. The SAR was revised to indicate that there will be one document published jointly by NERC and NAESB. This should satisfy commenters who indicated that having two documents would be confusing and a detriment to reliability.

Commenter	Yes	No	Comment
CP9 Reliability Standards Working Group Guy Zito Kathleen Goodman Khaqan Khan Vinod (Bob) Kotecha		X	This proposed standard change was not initiated due to reliability needs. NPCC Participating members believe that the change is in conflict to very important reliability rules. In order to understand the process the standard and the business practice are necessary.
Response: The proposed change was initiated to clearly distinguish reliability-related requirements from business practice requirements. The revised SAR indicates that there will be joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard will include the business practice requirements and the reliability requirements without need for separate documents.			
ISO NE Cheryl Mendrala		X	This proposed standard change was not initiated due to reliability needs
Response: The proposed change was initiated to clearly distinguish reliability-related requirements from business practice requirements. The revised SAR indicates that there will be joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard will include the business practice requirements and the reliability requirements without need for separate documents.			
Entergy Services, Transmission Ed Davis Rick Riley Jay Zimmerman George Bartlett James Case Bill Aycock Melinda Montgomery Narinder Saini Maurice Casadaban		X	The interplay between the business practices and reliability practices associated with TLR is so intimate that the two should not be divided into two standards practices. It would be best for the industry that one TLR standard be developed by the two organizations.
Response: Agreed. Since the first draft of this SAR was posted, the NERC NAESB Template Procedure for Joint Standards Development and Coordination was developed to ensure proper coordination for standards where there is no easy separation of business and reliability. The revised SAR indicates that there will be joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard will include the business practice requirements and the reliability requirements without need for separate documents.			
AEP Raj Rana		X	We support the NERC/NAESB initiative to split the TLR document in order extract the business practice aspects. However, there is no reliability need for this proposed standard change. The reliability need in terms by managing power flow relief in a pre-defined time period in order to maintain security of the system did not change. However, this draft does not provide

			reliability performance specifications, such as X MW or % of relief in Y minutes. The NERC portion of this standard should specify what is needed to maintain the system security in the interconnected environment, while the NAESB portion should specify the road map as to how to do it.
Response: The proposed change was initially initiated to clearly distinguish reliability-related requirements from business practice requirements. Since then, other stakeholders and FERC have identified the need for several additional changes to the standard beyond the NERC/NAESB coordinated split of the requirements. The revised SAR has an expanded scope to address all of these proposed changes. Please see the revised SAR.			
Midwest Reliability Organization Alan Boesch Terry Bilke Robert Coish Dennis Florom Todd Gosnell Wayne Guttormson Jim Maenner Tom Mielnik Darrick Moe Ken Goldsmith Joe Knight		X	The MRO does not believe there is a reliability need for the proposed standard change. We would contend that the change provides confusion to a very important reliability process. In order to understand the process the standard and the business practice are necessary.
Response: The proposed change was initiated to clearly distinguish reliability-related requirements from business practice requirements. The revised SAR indicates that there will be joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard will include the business practices and the reliability standards without need for separate documents.			
IESO, Ontario Dan Rochester		X	We do not feel there is a reliability need for the proposed standard "change". We would contend that the change provides confusion to a very important reliability process. In order to understand the process the standard and the business practice are necessary.
Response: The proposed change was initiated to clearly distinguish reliability-related requirements from business practice requirements. The revised SAR indicates that there will be joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard will include the business practices and the reliability standards without need for separate documents.			
Public Service Commission of South Carolina Phil Riley John E. Howard David A. Wright Randy Mitchell Elizabeth B. Fleming G. O'Neal Hamilton Mignon L. Clyburn C. Robert Moseley	X		
Ohio Valley Electric Corp. Scott R. Cunningham	X		
Joint Interchange Scheduling Working Group Bert Gumm Troy Simpson Marilyn Franz Jim Hansen Kathee Downing Jim Eckelcamp	X		

Bob Harshbarger Paul Sorenson Bob Schwermann Bonita Smulski Taryn McPherson Salah Kitali Joel Mickey Andrew Burke			
Southern Company – Transmission Jim Busbin Marc Butts Jim Viikinsalo	X		N/A
Operating Reliability Working Group (ORWG) Robert Rhodes Dan Boezio Bob Cochran Mike Crouch Todd Fridley Mike Gammon Serhly Kotsan Robert Rhodes	X		
Southern Company Generation Roman Carter Joel Dison Clifford Shepard Lucius Burris Steve Lowe	X		

2. **Do you believe the TLR Subcommittee appropriately divided the elements of TLR business practices vs. TLR reliability requirements? If not, please explain in the comment area.**

Summary Consideration: The comments do indicate some support, but not a clear consensus in support of the proposed division of TLR business practices versus TLR reliability requirements. In reviewing the comments, the drafting team notes that several of the comments imply that certain steps in Attachment 1 were proposed to be assigned as business practices, but those steps were not proposed as business practices in the first draft of the SAR.
The modifications made to the SAR should improve this consensus as many of the negative comments indicated that subdividing the requirements into two separate documents would be confusing and under the revised SAR NERC and NAESB will jointly publish a document that includes both the Business Practice requirements and the reliability requirements in a single document.

Commenter	Yes	No	Comment
IESO, Ontario Dan Rochester		X	The reliability and business practices within the TLR process are integrated to such an extent that the details need to remain contained within a single document for clarity. Concerns regarding the ability to effectively manage the model and the process with the current proposed split need to be addressed. The ability to follow developing market issues must also be retained. Steps 1.4.1, 1.4.1.1, 1.5, 1.5.1, 1.6, 1.7, 2.1.2, 2.2.2, 2.4.2, 2.5.2, 3.2.1.2, 3.3.1.2, 7.1, are reliability related and should remain in the standard. The dynamic schedule part of 1.6.6 was added to the Standard in June of this year with approval of 100% of the ballot body. It should remain as part of this standard.
Response: In determining how to subdivide the requirements, this is the approach taken by the TLR Task Force: A procedure includes steps that are performed to achieve expected results. It is only one method to achieve those results. If a Reliability Coordinator has options to address congestion and those options are prioritized in order of economic preference then the RC is making choices that would be appropriate under a business practice. In support of this approach, the drafting team believes that the following steps in the TLR Procedure should be assigned to a NAESB Business practice: 1.5.1, 2.2.2, 2.4.2, and 2.5.2. Note that the other steps in the process that you've identified, 1.4.1, 1.4.1.1, 1.5, 1.6, 1.7, 2.1.2, 3.2.1.2, 3.3.1.2, and 7.1 are retained as reliability-steps in the revised SAR. There were no changes to 1.6.6 as part of the approval of IRO-006-02.			
CP9 Reliability Standards Working Group Guy Zito Kathleen Goodman Khaqan Khan Vinod (Bob) Kotecha		X	- Section 2.6 and 2.7 in the original standard defined step-by-step actions the Operator is to take under TLR Levels 5a and 5b. These actions have been removed and currently reside in the proposed NAESB standard. It is not appropriate for a business practice standard to define actions to be taken by a Reliability Coordinator in real-time operations to resolve a reliability issue. The need for a TLR is in response to a problem with reliability on the system. The Operator must be presented with all the information that is contained in both the proposed NERC and NAESB standards in order to issue that TLR. If the operator does not know what transactions are available in any given category, they do not know what TLR level is needed to resolve the situation. NPCC participating members do not agree with the assertion that the information contained in the NAESB standard does not impact reliability. Some aspects of the original IRO-006 are 'business practices,' and that the completed effort generally meets the original intent of splitting the business practice and reliability components. However, seeing the resulting split, it is clear that these business practices have a direct impact on reliability and they should be maintained within one single standard to prevent confusion and conflicts. Also, since the fundamental practice for defining the priorities and treatment of transactions under each TLR level is consistent with the FERC pro-forma tariff, there is minimal subjectivity involved in the business practices that are included in the original NERC standard. Steps 1.4.1, 1.4.1.1, 1.5, 1.5.1, 1.6, 1.7, 2.1.2, 2.2.2, 2.4.2, 2.5.2, 3.2.1.2,

			3.3.1.2, 7.1, are reliability related and should remain in the standard. The dynamic schedule part of 1.6.6 was added to the Standard in June of this year with 100% of the ballot body approval, it should remain as part of this standard.
/Response: In determining how to subdivide the requirements, this is the approach taken by the TLR Task Force: A procedure includes steps that are performed to achieve expected results. It is only one method to achieve those results. If a Reliability Coordinator has options to address congestion and those options are prioritized in order of economic preference then the RC is making choices that would be appropriate under a business practice. In support of this approach, the drafting team believes that the following steps in the TLR Procedure should be assigned to a NAESB Business practice: 1.5.1, 2.2.2, 2.4.2, and 2.5.2. The revised SAR indicates that there will be joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard will include the business practices and the reliability standards without need for separate documents.			
Operating Reliability Working Group (ORWG) Robert Rhodes Dan Boezio Bob Cochran Mike Crouch Todd Fridley Mike Gammon Serhly Kotsan Robert Rhodes		X	We feel that the division between business practices and reliability standards may not have gone far enough. The reliability standards should focus on establishing the criteria for initiation of different TLR levels and the required timeframes for relief. Business practices should focus on how the curtailments are executed to achieve the relief levels in the timeframes required by the reliability standard.
Response: In determining how to subdivide the requirements, this is the approach taken by the TLR Task Force: A procedure includes steps that are performed to achieve expected results. It is only one method to achieve those results. If a Reliability Coordinator has options to address congestion and those options are prioritized in order of economic preference then the RC is making choices that would be appropriate under a business practice. The revised SAR indicates that there will be joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard will include the business practices and the reliability standards without need for separate documents.			
ISO NE Cheryl Mendrala		X	- Section 2.6 and 2.7 in the original standard defined step-by-step actions the Operator is to take under TLR Levels 5a and 5b. These actions have been removed and currently reside in the proposed NAESB standard. It is not appropriate for a business practice standard to define actions to be taken by a Reliability Coordinator in real-time operations to resolve a reliability issue. The need for a TLR is in response to a problem with reliability on the system. There is no doubt that the Operator must be presented with all the information that is contained in both the proposed NERC and NAESB standards in order to issue that TLR. If the operator does not know what transactions are available in any given category, they do not know what TLR level is needed to resolve the situation. Therefore, we cannot agree with the assertion that the information contained in the NAESB standard does not impact reliability. We agree that some aspects of the original IRO-006 are 'business practices,' and agree that the completed effort generally meets the original intent of splitting the business practice and reliability components. However, seeing the resulting split, it is clear that these business practices have a direct impact on reliability and we believe they should be maintained within one single standard to prevent confusion and conflicts. Also, since the fundamental practice for defining the priorities and treatment of transactions under each TLR level is consistent with the FERC pro-forma tariff, there is minimal subjectivity involved in the business practices that are included in the original NERC standard.
Response:			

The revised SAR indicates that there will be joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard will include the business practices and the reliability standards without need for separate documents. Note that in the revised SAR, all of the 'step-by-step' actions identified for TLR Levels 5a and 5b appear in the combined document. In determining how to subdivide the requirements, this is the approach taken by the TLR Task Force: A procedure includes steps that are performed to achieve expected results. It is only one method to achieve those results. If a Reliability Coordinator has options to address congestion and those options are prioritized in order of economic preference then the RC is making choices that would be appropriate under a business practice.			
Entergy Services, Transmission Ed Davis Rick Riley Jay Zimmerman George Bartlett James Case Bill Aycock Melinda Montgomery Narinder Saini Maurice Casadaban		X	A complete response to this question is inappropriate at this time. It appears that IRO-006 will be divided into 3 major documents: NERC TLR reliability standards, NAESB business practices, and the IDC Reference Documentation. The answer to this question will require a detailed comparison of all three documents with respect to the existing IRO-006. We do not have the NAESB document in front of us in order to make that detailed comparison. In addition, it does not appear that a detailed comparison of the three documents has been requested since the SAR request states in the last paragraph that the development effort will begin by assessing for completeness and accuracy the revised Attachment 1.
Response: In the future, the drafting team will make sure all documents needed for review are posted. The revised SAR indicates that there will be joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard will include the business practices and the reliability standards without need for separate documents.			
AEP Raj Rana		X	The two documents are overlapping. Same statements in both documents.
Response: Agreed – this duplication will be eliminated as indicated in the revised SAR. The revised SAR indicates that there will be joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard will include the business practices and the reliability standards without need for separate documents.			
Midwest Reliability Organization Alan Boesch Terry Bilke Robert Coish Dennis Florom Todd Gosnell Wayne Guttormson Jim Maenner Tom Mielnik Darrick Moe Ken Goldsmith Joe Knight The 31 Additional MRO Members		X	Steps 1.4.1, 1.4.1.1, 1.5, 1.5.1, 1.6, 1.7, 2.1.2, 2.2.2, 2.4.2, 2.5.2, 3.2.1.2, 3.3.1.2, 7.1, are reliability related and should remain in the standard. The dynamic schedule part of 1.6.6 was added to the Standard in June of this year with 100% of the ballot body approval, it should remain as part of this standard.
Response: In determining how to subdivide the requirements, this is the approach taken by the TLR Task Force: A procedure includes steps that are performed to achieve expected results. It is only one method to achieve those results. If a Reliability Coordinator has options to address congestion and those options are prioritized in order of economic preference then the RC is making choices that would be appropriate under a business practice. In support of this approach, the drafting team believes that the following steps in the TLR Procedure should be assigned to a NAESB Business practice: 1.5.1, 2.2.2, 2.4.2, and 2.5.2. Note that the other steps in the process that you've identified, 1.4.1, 1.4.1.1, 1.5, 1.6, 1.7, 2.1.2, 3.2.1.2, 3.3.1.2, and			

7.1 are retained as reliability-steps in the revised SAR. There were no changes to 1.6.6 as part of the approval of IRO-006-02.			
Southern Company – Transmission Jim Busbin Marc Butts Jim Viikinsalo	X		N/A
Joint Interchange Scheduling Working Group Bert Gumm Troy Simpson Marilyn Franz Jim Hansen Kathee Downing Jim Eckelcamp Bob Harshbarger Paul Sorenson Bob Schwermann Bonita Smulski Taryn McPherson Salah Kitali Joel Mickey Andrew Burke	X		
Public Service Commission of South Carolina Phil Riley John E. Howard David A. Wright Randy Mitchell Elizabeth B. Fleming G. O'Neal Hamilton Mignon L. Clyburn C. Robert Moseley	X		
Ohio Valley Electric Corp. Scott R. Cunningham	X		
Southern Company Generation Roman Carter Joel Dison Clifford Shepard Lucius Burris Steve Lowe	X		

3. Do you believe there are still elements of TLR business practices that remain in the proposed TLR reliability requirements? If not, please explain in the comment area.

Summary Consideration: Most commenters indicated that the TLR business practices have been removed from the TLR reliability requirements. Some commenters were not able to locate the NAESB Business Practice and could not easily answer this question. In the future, the drafting team will ensure that all documents needed to answer the questions on the comment forms are posted with the comment form.

Commenter	Yes	No	Comment
Ohio Valley Electric Corp. Scott R. Cunningham	X		At times, RTO ramp limitations are invoked when TLR curtailments occur. This issue is not covered in the standard, but seems to be related to a business practice, rather than a reliability issue. Perhaps the ramp limitation should be waived or adjusted if the limitation is caused by the curtailments that occur with the TLR.
Response: This is a change that could be addressed with the technical revisions to improve the standard in phase 2 of the proposed revisions.			
Operating Reliability Working Group (ORWG) Robert Rhodes Dan Boezio Bob Cochran Mike Crouch Todd Fridley Mike Gammon Serhly Kotsan Robert Rhodes	X		Everything in the proposed Attachment 1 - IRO-006-0 from Section 3 to the end of Attachment 1, including Appendices A and B, should be removed from the reliability standard and incorporated into the TLR Business Practices document. This material gets into the internal workings of the tool itself rather than dealing with the overall guiding principle of providing, and maintaining, relief within a specific timeframe.
Response: The drafting team agrees that many parts of Attachment 1 should be placed into either the Business Practices document or in a Technical Reference. The revised SAR indicates that there will be joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard will include the business practices and the reliability standards without need for separate documents. Appendix A may be a reference document for both the reliability standard and the business practice – Appendix B is expected to be included in the NAESB business practices.			
Entergy Services, Transmission Ed Davis Rick Riley Jay Zimmerman George Bartlett James Case Bill Aycock Melinda Montgomery Narinder Saini Maurice Casadaban	X		The NERC TLR reliability standard part of this documentation appears to be all reliability related. However, the IDC Reference Document appears to have significant business practice elements contained in it.
Response: Agreed. The revised SAR indicates that most of the content in the IDC Reference Document (Appendix E) should be translated into a reference document.			
AEP Raj Rana	X		We believe that items like firm/non-firm transactions types, TLR levels etc. should be taken out of the reliability portion of this standard. These items should be included in the NAESB portion. The reliability portion should only address the needed relief amount on constrained facilities and the time under which the relief should be provided in order to maintain security of the interconnected network.
Response: In determining how to subdivide the requirements, this is the approach taken by the TLR Task Force: A procedure includes steps that are performed to achieve expected results. It is only one method to achieve those			

results. If a Reliability Coordinator has options to address congestion and those options are prioritized in order of economic preference then the RC is making choices that would be appropriate under a business practice. The Attachment 1 steps of the procedure have been identified by the TLR Taskforce as having both Reliability and business practices within them. As the resulting standard will be published jointly all items are expected to be retained and the distinction of the items as reliability or as business practices will be identified.			
ISO NE Cheryl Mendrala		X	See response to question 2.
Response: See response to comments on question 2.			
CP9 Reliability Standards Working Group Guy Zito Kathleen Goodman Khaqan Khan Vinod (Bob) Kotecha		X	See response to question 2.
Response: See response to comments on question 2.			
Southern Company – Transmission Jim Busbin Marc Butts Jim Viikinsalo		X	N/A
Joint Interchange Scheduling Working Group Bert Gumm Troy Simpson Marilyn Franz Jim Hansen Kathee Downing Jim Eckelcamp Bob Harshbarger Paul Sorenson Bob Schwermann Bonita Smulski Taryn McPherson Salah Kitali Joel Mickey Andrew Burke		X	
Midwest Reliability Organization Alan Boesch Terry Bilke Robert Coish Dennis Florom Todd Gosnell Wayne Guttormson Jim Maenner Tom Mielnik Darrick Moe Ken Goldsmith Joe Knight The 31 Additional MRO Members		X	
Public Service Commission of South Carolina Phil Riley John E. Howard David A. Wright Randy Mitchell Elizabeth B. Fleming G. O'Neal Hamilton		X	

Mignon L. Clyburn C. Robert Moseley			
IESO, Ontario Dan Rochester		X	
Southern Company Generation Roman Carter Joel Dison Clifford Shepard Lucius Burris Steve Lowe		X	

4. **Do you believe there are still elements of TLR reliability requirements that remain in the proposed TLR business practices? If not, please explain in the comment area.**

Summary Consideration: Most commenters indicated that there aren't TLR reliability requirements in the proposed TLR business practices. Some commenters were not able to locate the NAESB Business Practice and could not easily answer this question. In the future, the drafting team will ensure that all documents needed to answer the questions on the comment forms are posted with the comment form.

Commenter	Yes	No	Comment
AEP Raj Rana			No comments. The TLR business practices document is not available.
Response: In the future, the drafting team will make sure all relevant documents are posted.			
Operating Reliability Working Group (ORWG) Robert Rhodes Dan Boezio Bob Cochran Mike Crouch Todd Fridley Mike Gammon Serhly Kotsan Robert Rhodes	X		Sections 3.2.1, 3.2.1.1 and 3.2.1.2 should be moved to the reliability standard since they deal more with how and why a Level 2 TLR is initiated than with the internal workings of the IDC.
Response: In determining how to subdivide the requirements, this is the approach taken by the TLR Task Force: A procedure includes steps that are performed to achieve expected results. It is only one method to achieve those results. If a Reliability Coordinator has options to address congestion and those options are prioritized in order of economic preference then the RC is making choices that would be appropriate under a business practice. Note that in the revised SAR, 3.2.1.2 is included in the reliability related steps of the procedure.			
ISO NE Cheryl Mendrala	X		See response to question 2.
Response: See response to comments on question 2.			
CP9 Reliability Standards Working Group Guy Zito Kathleen Goodman Khaqan Khan Vinod (Bob) Kotecha	X		See response to question 2.
Response: See response to comments on question 2.			
Midwest Reliability Organization Alan Boesch Terry Bilke Robert Coish Dennis Florom Todd Gosnell Wayne Guttormson Jim Maenner Tom Mielnik Darrick Moe Ken Goldsmith Joe Knight The 31 Additional MRO Members	X		See comments in question 2.
Response: See respone to comments on question 2			
IESO, Ontario		X	See comments in question 2.

<table>
<tr><td>Dan Rochester</td><td></td><td></td><td></td></tr>
<tr><td colspan="4">Response: See response to comments on question 2.</td></tr>
<tr><td>Entergy Services, Transmission
Ed Davis
Rick Riley
Jay Zimmerman
George Bartlett
James Case
Bill Aycock
Melinda Montgomery
Narinder Saini
Maurice Casadaban</td><td></td><td>X</td><td>We can not answer this question since we do not have the NAESB proposal TLR business practices in this package.</td></tr>
<tr><td colspan="4">Response: In the future, the drafting team will make sure all relevant documents are posted.</td></tr>
<tr><td>Southern Company – Transmission
Jim Busbin
Marc Butts
Jim Viikinsalo</td><td></td><td>X</td><td>N/A</td></tr>
<tr><td>Joint Interchange Scheduling Working Group
Bert Gumm
Troy Simpson
Marilyn Franz
Jim Hansen
Kathee Downing
Jim Eckelcamp
Bob Harshbarger
Paul Sorenson
Bob Schwermann
Bonita Smulski
Taryn McPherson
Salah Kitali
Joel Mickey
Andrew Burke</td><td></td><td>X</td><td></td></tr>
<tr><td>Public Service Commission of South Carolina
Phil Riley
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C. Robert Moseley</td><td></td><td>X</td><td></td></tr>
<tr><td>Ohio Valley Electric Corp.
Scott R. Cunningham</td><td></td><td>X</td><td></td></tr>
<tr><td>Southern Company Generation
Roman Carter
Joel Dison
Clifford Shepard
Lucius Burris
Steve Lowe</td><td></td><td>X</td><td></td></tr>
</table>

5. Do you have any other comments on these proposed changes?

Summary Consideration:
The NERC-NAESB Procedure for Joint Development and Coordination was established after the first posting of this SAR, to guide joint development of standards and business practices when the reliability and business practice components are intricately entwined within a proposed standard. This procedure has been approved for implementation by the Standards Committee, NERC Board of Trustees and the NAESB Board and is applicable to the revisions of IRO-006. The revisions made to IRO-006 will be jointly published by NERC and NAESB in a single document, thus eliminating the need for a real-time system operator to have two documents that must be merged together to provide the needed information.

Several commenters suggested modifications to some of the requirement in the standard and/or to some of the steps in the TLR process. The drafting team modified its SAR to clearly indicate that the revisions to IRO-006 will be addressed in phases – with assigning the steps in Attachment 1 of IRO-006 between NERC/NAESB as the first phase – and addressing technical revisions that require field testing, changes to the IDC, and other modifications already identified as needed to improve the overall quality of the standard being addressed following the NERC/NAESB split. Stakeholder suggestions for technical modifications that were made in response to this question have been added to the laundry list of items under the IRO-006 'To Do List'.

Commenter	Yes	No	Comment
Southern Company – Transmission Jim Busbin Marc Butts Jim Viikinsalo	X		My only concern with the splitting of reliability requirements and business practices is how they will be managed and/or coordinated in the future. I'm not sure what value is added to the reliability of the grid by now having our grid operators manage their respective systems with a NERC manual in one hand and a NAESB manual in the other. Right now the two documents are in synch with one another; however, as we move forward in time, what will be the process for conflict resolution between the two?
Response: Note that following the first posting of this SAR, NERC and NAESB jointly developed and adopted a procedure to ensure that when a reliability standard and business practice are 'entwined', the development (and revision) would be coordinated between the two organizations. The revised SAR indicates that there will be joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard will include the business practices and the reliability standards without need for separate documents.			
Operating Reliability Working Group (ORWG) Robert Rhodes Dan Boezio Bob Cochran Mike Crouch Todd Fridley Mike Gammon Serhly Kotsan Robert Rhodes	X		Section 1.5.1 of Attachment 1 refers to treatment of Interchange Transactions not in the IDC in accordance with NAESB business practices, but we could not find any reference to this treatment in the TLR business practices.
Response: This is in Sections 1.1, 1.2, 1.2.11 of NAESB Transmission Loading Relief Business Practice and is shown in the proposed revisions to Attachment 1.			

ISO NE Cheryl Mendrala	X		Recommend restoring the reference to RCIS tool in 1.4. That reference was eliminated when the old 1.4.1 was removed. - The old 1.5.1 was removed. There's a general statement added to 1.2 that says "In addition, a Reliability Coordinator may implement other NERC-approved procedures to request relief to mitigate any other transmission constraints as necessary to preserve the reliability of the system." But, that phrase does not seem to capture the same intent as the previous 1.5.1 wording. - Section 1.5.3 the numbering on this section is very confusing. Suggest the following: 1.5.3.1. Causes of questionable IDC results may include: (1) Missing Interchange transactions that are known to contribute to the Constraint, (2) Significant change in transmission system topology, or (3) TDF matrix error. 1.5.3.2 Impacts of questionable IDC results may include: (1) relief that would have no effect on, or aggravate the constraint or (2) that would initiate a constraint elsewhere. 1.5.3.3. If other Reliability Coordinators are involved in the TLR event, all impacted Reliability Coordinators shall be in agreement before any adjustments to the relief request list are made. - Title of Section 2 should be changed to be only "Transmission Loading Relief (TLR) Levels." - Section 3 is missing section 3.1. - Suggest that Section 3.2 include a reference to the fact that transactions submitted after the XX:25 deadline will put on HOLD. - Are Section 3.3.3 and Section 3.4.3 referring back to the deadline defined in 3.2? If so, that section should be referenced. - Text in 3.3.1.1 and 3.3.2 are referring to the same process for reallocation and should use the same terminology. Suggest 3.3.1.1 text be changed to "At XX:25 a reallocation will be performed for the following hour to maintain the target flow identified for the current hour". - Text in 3.4.1.1 and 3.4.2 are referring to the same process for reallocation and should use the same terminology. Suggest 3.4.1.1 text be changed to "At XX:25 a reallocation will be performed for the following hour to maintain the target flow identified for the current hour". - The section notation of Appendix B should be modified. The Section numbering shown in the index is not how the headings are titled in the Sections. Also, Section F and Section G should not be 5.1 and 5.2; they should be at the highest index level. General Comment: There have been changes to the congestion management process over the last few years that involve the use of Market information by the IDC. Any new standards addressing the TLR process and the IDC, whether in NERC or NAESB, should consider addressing the current information available to the IDC and include some mention of that information in that standard development. General Comment: One other practical concern that has not been addressed is the ownership, impact and funding of the IDC tool that automates the 'business practices' of implementing a TLR for the Operator. The split of the original NERC IRO-006 should not be adopted until this issue is addressed and resolved.
As noted in the revised SAR, the standard will be revised in phases – the first phase will be limited to the 'NERC/NAESB/ split' – but following that split, the standard drafting team will be focusing on the laundry list of technical improvements to the standard that have already been identified in the SAR – and will add your list to those that will be considered. The reference was moved to NAESB BP 1.4 and changed to refer to generic tool instead of RCIS specifically. This approach limits the number of changes that need to be made to standards when the tool or committee name changes.			

Section 3.1 does appear in the revised proposed changes to Attachment 1. Going forward the changes will be managed from the joint standards development process and there is no anticipated change in the funding or contract agreements to modify the software. The standard drafting team will determine the best way to format and number the steps in the procedure jointly.			
Entergy Services, Transmission Ed Davis Rick Riley Jay Zimmerman George Bartlett James Case Bill Aycock Melinda Montgomery Narinder Saini Maurice Casadaban	X		The SAR contains the statement that the urgent action revision to Attachment 1 addressing dynamic schedules will be incorporated into the NAESB business practices. We suggest starting with IRO-006-1, rather than with IRO-006-0. Please delete all references to IRO-006-0 (and IRO-006-1) in headers, footers, titles, etc. This new document will result in a new version of IRO--006. This current draft is not version 0 or 1. Please delete all references to adoption by the NERC Board of Trustees, Effective Date, and all dates because the document we are viewing has not been adopted by the BOT and does not have an Effective Date. Please provide a redline version showing the draft changes to IRO-006-1. This redline would make review and comment much easier for commenters. We appreciate the development of the matrix and would probably find it useful for keeping track of the disposition of each requirement in the original IRO-006. However, in its current form we do not understand which columns relate to which documents and the row designations are not clearly understood.
Response: The standard drafting team will make its revisions to the latest approved version of the standard – which is now IRO-006-03. Headers, footers, etc will be corrected when the draft standard is posted for review and comment. The SAR was revised to identify the scope of changes that will be made, without trying to make all those changes since that is really the work of the standard drafting team – there is no red line to the standard as the proposed changes to the standard will be refined by the standard drafting team. The matrix was confusing and will not be carried forward.			
Joint Interchange Scheduling Working Group Bert Gumm Troy Simpson Marilyn Franz Jim Hansen Kathee Downing Jim Eckelcamp Bob Harshbarger Paul Sorenson Bob Schwermann Bonita Smulski Taryn McPherson Salah Kitali Joel Mickey Andrew Burke	X		1. We request that the scope of this SAR be expanded to include resolving the reloading of curtailed transactions above their reliability limit by an entity other than the initiating entity or above any pre-existing reliability or market profiles. 2. We also request that the scope of the SAR be expanded to include standards for when curtailments may be denied and when curtailments may be issued. 1 - There have been several instances where a curtailment has been issued and then been automatically or manually reloaded above the reliability limit. The automatic reload problem created by the IDC has been resolved by CO-148, automatic reload by other back office applications has not been corrected, nor have manual adjustments. There are several options available for correcting this problem. This should be addressed by specifying requirements and performance measures in the TLR standard and may also be addressed through NAESB business practices and modifications to the e-Tag specification. Also, any pre-existing curtailment levels are lost. JISWG recommends that the entity who has issued the curtailment be the only entity able to authorize the reload. When the reload occurs the energy profile should be limited to the next lowest reliability limit or market adjustment profile. 2- Under normal circumstances, a curtailment (issued for reliability reasons) should not be denied. However, there are some limited circumstances where a curtailment should be denied. For example, if a curtailment comes in and the generator cannot meet the ramp requirements, then the curtailment could be denied and would be reissued for the next scheduling interval. This ensures that the tags reflect actual conditions. In other cases, curtailments are sometimes issued when PSE's cannot make their market level adjustments prior to cutoff. The TLR standard should address those specific reasons for denying a curtailment. Reliability is compromised when curtailments are denied for non-reliability reasons. Reliability may also be compromised when curtailments are issued for non-reliability reasons. If scope of the SAR is adjusted, JISWG volunteers to assist the drafting team with providing specific language for the TLR standard addressing these issues.
Response: As noted in the revised SAR, the standard will be revised in phases – the first phase will be limited to the 'NERC/NAESB/ split' – but following that split, the standard drafting team will be focusing on the laundry list of			

technical improvements to the standard that have already been identified in the SAR – and will add your list to those that will be considered.			
AEP Raj Rana	X		Use of proxy flowgates by the reliability coordinators must be prohibited. This practice must be explicitly addressed in this standard because, the use of proxy flowgates not only will result in mis-allocation of corrective actions, but at worst could even result in actions being taken that actually increase flows on the limiting element, instead of decreasing them.
Response: As noted in the revised SAR, the standard will be revised in phases – the first phase will be limited to the 'NERC/NAESB/ split' – but following that split, the standard drafting team will be focusing on the laundry list of technical improvements to the standard that have already been identified in the SAR – and will add your list to those that will be considered.			
Midwest Reliability Organization Alan Boesch Terry Bilke Robert Coish Dennis Florom Todd Gosnell Wayne Guttormson Jim Maenner Tom Mielnik Darrick Moe Ken Goldsmith Joe Knight The 31 Additional MRO Members	X		It was very difficult to review the changes to the standard without a redline copy. In order to perform our review we made a redline of the original standard. The MRO does not support this modification. The proposed change provides confusion to a very important reliability process. Also the proposed standard references a NAESB standard which is inconsistent with the NERC Standards Process Manual which says "All mandatory requirements of a reliability standard shall be within an element of the standard. Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself." There are mandatory parts of the proposed standard in the NAESB business practice and are necessary for the successful implementation of this reliability standard. With the two documents being modified by separate entities there is a good chance that the documents will not be coordinated and kept in synchronization when changes are made.
Response: The NERC NAESB Template Procedure for Joint Standards Development and Coordination was developed to ensure proper coordination for standards where there is no easy separation of business and reliability. The approach includes joint collaboration and joint publication of the resulting standard. There will be one jointly published document which covers both the business practice steps and the reliability steps of the Attachment in IRO-006.			
Ohio Valley Electric Corp. Scott R. Cunningham	X		The use of proxy flowgates is not mentioned at all in the proposed standard. The use of proxy flowgates should not be allowed, except in very unusual circumstances. If use of a proxy flowgate is necessary, such use should be justified and approval from all affected parties should be obtained.
Response: As noted in the revised SAR, the standard will be revised in phases – the first phase will be limited to the 'NERC/NAESB/ split' – but following that split, the standard drafting team will be focusing on the laundry list of technical improvements to the standard that have already been identified in the SAR – and will add your list to those that will be considered.			
IESO, Ontario Dan Rochester	X		The IESO does not fully support the modifications proposed in this SAR. The proposed change provides confusion to a very important reliability process. Also the proposed standard references a NAESB standard which is inconsistent with the NERC Standards Process Manual which says "All mandatory requirements of a reliability standard shall be within an element of the standard. Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself." There are mandatory parts of the proposed standard in the NAESB business practice that are necessary for the successful implementation of this reliability standard. With the two documents being modified by separate entities there is a good chance that the documents will not be coordinated and kept in synchronization when changes are made. As acknowledged by the TLR Subcommittee that worked to create this proposed split, the business practices and reliability aspects of TLR are very intertwined. In effect, the information in both the proposed NERC and NAESB standard must be simultaneously available to the Operators in the Control Room, in order for them to operate the system reliably. While the effort to create this initial split in the TLR standards has been completed,

			consideration should be given as to how this split will be maintained, if going forward, before it is adopted by the industry. Operator training issues, as well as the ownership and funding of the IDC tool should be considered in this evaluation before such a significant step is taken on a standard that is fundamental to the reliability of the Eastern Interconnection. This is an important process that requires a complete understanding of the impact of separating the business practice from the reliability concepts. It is not clear that the current proposed document split will retain the integrity of the TLR process. The potential negative impact of degrading the RC's ability to manage loop flow dictates that any change in documentation and responsibility must proceed carefully.
Response: The NERC NAESB Template Procedure for Joint Standards Development and Coordination was developed to ensure proper coordination for standards where there is no easy separation of business practices and reliability requirements. The approach includes joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard includes the business practices and the reliability standards without need for separate documents. The IDC is the tool that specifies how the Business Practice and the Reliability adjustments are made. The RC specifies how much relief is required and the tool combines the logic based on business practice rules to identify how much relief in each transaction should be distributed. NERC will work jointly to provide training when needed by using the committees and then by providing the necessary materials so the industry can train their staff on			
Southern Company Generation Roman Carter Joel Dison Clifford Shepard Lucius Burris Steve Lowe	X		As NAESB and NERC standards are approved and implemented which require close coordination between the two organizations, the need for a common "Operations Manual" may become necessary for System Operators.
Response: The NERC NAESB Template Procedure for Joint Standards Development and Coordination was developed to ensure proper coordination for standards where there is no easy separation of business practices and reliability requirements. The approach includes joint collaboration and joint publication of the resulting standard. The joint collaboration ensures during development issues can be addressed jointly so that the resulting business practice and reliability standards work together. Using this process the result is that the jointly published standard includes the business practices and the reliability standards without need for separate documents.			
CP9 Reliability Standards Working Group Guy Zito Kathleen Goodman Khaqan Khan Vinod (Bob) Kotecha	X		This is an important process that requires a complete understanding of the impact of separating the business practice from the reliability concepts. It is not clear that the current proposed document split will retain the integrity of the TLR process. The potential negative impact of degrading the RC's ability to manage loop flow dictates that any change in documentation and responsibility must proceed carefully. NPCC participating Members believe the proposed change provides confusion to a very important reliability process. There are mandatory parts of the proposed standard in the NAESB business practice that are necessary for the successful implementation of this reliability standard. With the two documents being modified by separate entities there is a good chance that the documents will not be coordinated and kept in synchronization when changes are made. Recommend restoring the reference to RCIS tool in 1.4. That reference was eliminated when the old 1.4.1 was removed. - The old 1.5.1 was removed. There's a general statement added to 1.2 that says "In addition, a Reliability Coordinator may implement other NERC-approved procedures to request relief to mitigate any other transmission constraints as necessary to preserve the reliability of the system." But, that phrase does not seem to capture the same intent as the previous 1.5.1 wording.

			- Section 1.5.3 the numbering on this section is very confusing. Suggest the following: 1.5.3.1. Causes of questionable IDC results may include: (1) Missing Interchange transactions that are known to contribute to the Constraint, (2) Significant change in transmission system topology, or (3) TDF matrix error. 1.5.3.2 Impacts of questionable IDC results may include: (1) relief that would have no effect on, or aggravate the constraint or (2) that would initiate a constraint elsewhere. 1.5.3.3. If other Reliability Coordinators are involved in the TLR event, all impacted Reliability Coordinators shall be in agreement before any adjustments to the relief request list are made. - Title of Section 2 should be changed to be only "Transmission Loading Relief (TLR) Levels." - Section 3 is missing section 3.1. - Suggest that Section 3.2 include a reference to the fact that transactions submitted after the XX:25 deadline will put on HOLD. - Are Section 3.3.3 and Section 3.4.3 referring back to the deadline defined in 3.2? If so, that section should be referenced. - Text in 3.3.1.1 and 3.3.2 are referring to the same process for reallocation and should use the same terminology. Suggest 3.3.1.1 text be changed to "At XX:25 a reallocation will be performed for the following hour to maintain the target flow identified for the current hour". - Text in 3.4.1.1 and 3.4.2 are referring to the same process for reallocation and should use the same terminology. Suggest 3.4.1.1 text be changed to "At XX:25 a reallocation will be performed for the following hour to maintain the target flow identified for the current hour". - The section notation of Appendix B should be modified. The Section numbering shown in the index is not how the headings are titled in the Sections. Also, Section F and Section G should not be 5.1 and 5.2; they should be at the highest index level. General Comment: There have been changes to the congestion management process over the last few years that involve the use of Market information by the IDC. Any new standards addressing the TLR process and the IDC, whether in NERC or NAESB, should consider addressing the current information available to the IDC and include some mention of that information in that standard development. In addition, Operator training issues, as well as the ownership and funding of the IDC tool should be considered in this evaluation before such a significant step is taken on a standard that is fundamental to the reliability of the Eastern Interconnection. General Comment: One other practical concern that has not been addressed is the ownership, impact and funding of the IDC tool that automates the 'business practices' of implementing a TLR for the Operator. The split of the original NERC IRO-006 should not be adopted until this issue is addressed and resolved.

Response: As noted in the revised SAR, the standard will be revised in phases – the first phase will be limited to the 'NERC/NAESB/ split' – but following that split, the standard drafting team will be focusing on the laundry list of technical improvements to the standard that have already been identified in the SAR – and will add your list to those that will be considered.

The reference was moved to NAESB BP 1.4 and changed to refer to generic tool instead of RCIS specifically. This approach limits the number of changes that need to be made to standards when the tool or committee name changes.

Section 3.1 does appear in the revised proposed changes to Attachment 1.

Going forward the changes will be managed from the joint standards development process and there is no anticipated change in the funding or contract agreements to modify the software.
The standard drafting team will determine the best way to format and number the steps in the procedure jointly.

Public Service Commission of South Carolina Phil Riley John E. Howard David A. Wright Randy Mitchell Elizabeth B. Fleming G. O'Neal Hamilton Mignon L. Clyburn C. Robert Moseley		X	

Standard Authorization Request Form

Title of Proposed Standard **Revisions to IRO-06 Reliability Coordination - General Update**	
Request Date	07/14/05 Revised: 11/20/06

SAR Requestor Information	**SAR Type** (Put an 'x' in front of one of these selections)	
Name David Zwergel	☐	New Standard
Primary ContactDavid Zwergel	☒	Revision to existing Standard
Telephone (317) 249-5452 Fax (317) 249-5910	☐	Withdrawal of existing Standard
E-mail dzwergel@midwestiso.org	☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

The purpose of this standard is to ensure that overloads on critical transmission system limits are relieved within 30 minutes.

The purpose of revising this standard is to:

1. Provide an adequate level of reliability for the North American bulk power systems — ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure it 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.
3. Incorporate 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 attached 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.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies by double clicking the grey boxes.)*		
☒	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☐	Planning Authority	Plans the bulk electric system
☐	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
☐	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☒	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☒	Transmission Owner	Owns transmission facilities
☒	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☒	Generator Owner	Owns and maintains generation unit(s)
☒	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☒	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☒	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☒	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check boxes for all that apply by double clicking the grey boxes.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

Revisions to this standard fall into three categories:

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

- A second set of modifications to this standard involves further consideration of a change to the market flow calculation specified in MISO, PJM 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. This change would replace the SPP Urgent Action Regional Difference to IRO-006.

- 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 attached Standard Review Form and Reliability Standard Review Guidelines).

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.

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	Explanation

Standard Review Form Project 2006-08 Transmission Loading Relief		
Standard #	**IRO-006-3**	**Comments**
Title	Reliability Coordination – Transmission Loading Relief	Okay
Purpose		1st sentence is scope of job, not purpose – poor wording on 30 minute item. No benefit or value proposition.
Applicability		TO not in Requirements.
Requirements	*Conditions*	Okay
	Who?	While others are handled within text, PJM/MISO is cited as regional difference but not handled within text. Added SPP regional difference but nothing in text.
	Shall do what?	R1 – need something about overloads or similar wording R2 – uses interregional & sub-regional; check capitalization
	Result or Outcome	Missing
Measures		Single generic statement.
To Do List	FERC NOPR o Include a clear warning that TLR procedure is an inappropriate and ineffective tool to mitigate actual IROL violations; o Identify in a Requirement the available alternatives to use of the TLR procedure to mitigate an IROL violation; and o Include Measures and Levels of Non-Compliance that address each Requirement. o (see report for comments on regional differences) FERC staff report o R2 doesn't address blackout item that TLR shouldn't be used for SOL violation V0 Industry Comments o Usage of TLR log questioned o Some inconsistencies with current usage VRF Comments o R2.1, .2 & .3 – not a requirement, just a suggested instruction o R6 – redundant TLR SAR Comments o Provide reliability performance specifications, such as X MW or % of relief in Y minutes o Address consideration of ramp limits during TLR o Section 3.2 - include a reference to the fact that transactions submitted after the XX:25 deadline will put on HOLD o 3.3.1.1 and 3.3.2 are referring to the same process for reallocation and should use the same terminology o 3.4.1.1 and 3.4.2 are referring to the same process for reallocation and should use the same terminology	

	o Consider addressing the current information available to the IDC and include some mention of that information in that standard development (NERC or NAESB) o Resolve the reloading of curtailed transactions above their reliability limit by an entity other than the initiating entity or above any pre-existing reliability or market profiles o Provide criteria to identify when curtailments may be denied and when curtailments may be issued o Include a requirement that prohibits the Reliability Coordinator's use of proxy flowgates	
Misc. Items		Several compliance items missing. Inconsistency in handling ERCOT & western vs. eastern TLR procedure (attachment vs. web link).

Standard Review Guidelines

Applicability

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?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

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? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose

Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements

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?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability

Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations

Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness

Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance

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

Clear Language

Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality

Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements

In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology

To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Mitigation Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

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

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replace existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor

Replace, 'Regional Reliability Organization' with 'Electric Reliability Organization'

Bulk Electric System

Replace, ‘Bulk Electric System’ with ‘bulk power system’

Fill-in-the-blank Requirements

Do not include any ‘fill-in-the-blank’ requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, ‘Associated Documents’.

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 the SAR and assembled a drafting team on December 5, 2006.
2. The revisions to IRO-006 to transfer business practice content to NAESB were approved as IRO-006-4 by the Board of Trustees on October 23, 2007.
3. The SDT has developed this first draft for industry consideration.

Description of Current Draft:

This is the first draft of the proposed standard posted for stakeholder comments.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to Comments (Draft 1).	February 26, 2009
2. Posting for Comment (Draft 2).	February 26, 2009
3. Respond to Comments (Draft 2).	June 26, 2009
4. Posting for 30-day Pre-Ballot Review.	June 26, 2009
5. Initial Ballot.	July 27, 2009
6. Respond to comments.	September 10, 2009
7. Recirculation ballot.	September 10, 2009
8. Board adoption.	October 2009

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.

None.

A. Introduction

1. **Title:** **Reliability Coordination — Transmission Loading Relief (TLR)**

2. **Number:** **IRO-006-5**

3. **Purpose:** To provide Interconnection-wide transmission loading relief procedures that can be used to prevent or manage potential or actual SOL and IROL violations to maintain reliability of the bulk electric system.

4. **Applicability:**

   4.1. Reliability Coordinators.

5. **Proposed Effective Date:** First day of the first calendar quarter that after the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Reliability Coordinator that uses an Interconnection-wide congestion management procedure shall use the procedure for its Interconnection identified below: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

- The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection provided in IRO-006-5-EI.
- The Interconnection-wide transmission loading relief procedure for use in the Western Interconnection isWECC-IRO-STD-006-0 provided at: ftp://www.nerc.com/pub/sys/all_updl/standards/rrs/IRO-STD-006-0_17Jan07.pdf.
- 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

R2. Each Reliability Coordinator that receives a request pursuant to an Interconnection-wide transmission loading relief procedure listed in R1 above from a Reliability Coordinator in another Interconnection to curtail or reload an Interchange Transaction that crosses an Interconnection boundary shall comply with the request. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

C. Measures

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   Regional Entity.

   1.2. Compliance Monitoring Period and Reset Time Frame

   Not applicable.

   1.3. Data Retention

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

- The Reliability Coordinator shall maintain evidence to show compliance with R1 and R2 for the most recent calendar year plus the current year.
- If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL

E. Regional Differences

None.

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
4		Completed NERC/NAESB split	Revision
5		Removed Attachment 1 and made into a new standard, eliminated unnecessary requirements.	Revision

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 the SAR and assembled a drafting team on December 5, 2006.
2. The revisions to IRO-006 to transfer business practice content to NAESB were approved as IRO-006-4 by the Board of Trustees on October 23, 2007.
3. The SDT has developed this first draft for industry consideration.

Description of Current Draft:

This is the first draft of the proposed standard posted for stakeholder comments.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Respond to Comments (Draft 1).	February 26, 2009
2. Posting for Comment (Draft 2).	February 26, 2009
3. Respond to Comments (Draft 2).	June 26, 2009
4. Posting for 30-day Pre-Ballot Review.	June 26, 2009
5. Initial Ballot.	July 27, 2009
6. Respond to comments.	September 10, 2009
7. Recirculation ballot.	September 10, 2009
8. Board adoption.	October 2009

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.

~~**Reallocation:** The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.~~ (To be retired.)

Market Flow: the amount of energy flowing across a specified facility or set of facilities due to the operation of a market that has implemented a "Market Flow Calculation" methodology.

A. Introduction

1. **Title: Transmission Loading Relief Procedure for the Eastern Interconnection**

2. **Number:** IRO-006-EI-1

3. **Purpose:** To provide an Interconnection-wide transmission loading relief procedure (TLR) for the Eastern Interconnection that can be used to prevent and/or mitigate potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations to maintain reliability of the bulk electric system.

4. **Applicability:**

   4.1. Reliability Coordinators in the Eastern Interconnection.

5. **Effective Date:** First day of the first calendar quarter that after the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. The Reliability Coordinator shall not use the Eastern Interconnection TLR procedure alone to mitigate an actual IROL violation. When responding to an actual IROL violation, each Reliability Coordinator shall implement other actions prior to or in conjunction with the initiation of this TLR procedure, including, but not limited to, the following: reconfiguration, redispatch, use of demand-side management, load shedding.

R2. When initiating the Eastern Interconnection TLR procedure to prevent or mitigate a SOL or IROL violation, and at least every clock hour after initiation, up to and including the hour when the TLR level has been identified as TLR Level 0, the Reliability Coordinator shall identify: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

R2.1. The TLR level in accordance with the criteria in Appendix A, and

R2.2. A proposal for actions to take, based on the TLR level chosen.

R3. Upon the identification of the TLR level and a proposal for actions to take based on the TLR level chosen, the Reliability Coordinator initiating this TLR procedure shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

R3.1. Notify all Reliability Coordinators in the Eastern Interconnection of the identified TLR level

R3.2. Communicate the proposed actions to take to:

R3.2.1. All Reliability Coordinators in the Eastern Interconnection, and

R3.2.2. Those Reliability Coordinators in other Interconnections responsible for curtailing or reloading Interchange Transactions crossing Interconnection boundaries identified in the proposed actions.

R3.3. Request that the following entities implement the proposed actions identified in R2.2: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

R3.3.1. Each Reliability Coordinator associated with a Sink Balancing Authority in the Eastern Interconnection for which Interchange Transactions are proposed for curtailment or reloading

R3.3.2. Each Reliability Coordinators associated with a Balancing Authority in the Eastern Interconnection for which Network Integration Transmission Service or Native Load is proposed for curtailment or reloading

R3.3.3. Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection proposed to provide Market Flow curtailment or reloading.

R3.3.4. Each Reliability Coordinators associated with a Balancing Authority in the Eastern Interconnection operating a DC-tie for an Interchange Transaction sinking outside the Eastern Interconnection and crossing an interconnection boundary with an Interchange Transaction proposed for curtailment or reloading.

R4. Each Reliability Coordinator in the Eastern Interconnection that responds to a request as described in R3.3. shall comply with the request by taking one or more of the following actions: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

R4.1. Implement the communicated actions requested by the issuing Reliability Coordinator as follows:

- Direct its Balancing Authorities to implement the Interchange Transaction schedule change requests.
- Direct its Balancing Authorities to provide the Network Integrated Transmission Service and Native Load schedule changes for which the Balancing Authorities are responsible.
- Direct its Balancing Authorities to provide the Market Flow schedule changes for which the Balancing Authorities are responsible.

R4.2. Implement a procedure pre-approved by the ERO for use by the responding Reliability Coordinator in lieu of implementing some or all of the requested actions in R4.1, provided that its implementation is expected to prevent or mitigate the SOL or IROL violation with the same or greater effect than the actions not implemented in R4.1.

R4.3. Implement alternate actions to those in R4.1 or R4.2 provided that

R4.3.1. Analysis shows that some or all of the actions in R4.1 or R4.2 will result in a reliability concern or will be ineffective, and

R4.3.2. The alternate actions have been agreed to by the initiating Reliability Coordinator, and

R4.3.3. Analysis shows that the alternate actions will not adversely affect reliability.

R5. Each Reliability Coordinator that responds to a TLR event shall acknowledge to the initiating Reliability Coordinator the actions it will take pursuant to Requirement R4 within thirty minutes of receiving the request. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

C. Measures (Measures and Compliance Information Will Be Added Later)

M1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility:

1.2. Compliance Monitoring Period and Reset Time Frame:

1.3. Data Retention

Measure	Entity	Data Retention Period

2. Additional Compliance Information:

2.1.

2.2.

3. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL

E. Regional Differences

None.

F. Associated Documents

Revision History

Version	Date	Action	Tracking
1		Creation of new standard, incorporating concepts from IRO-006-4 Attachment; elimination of Regional Differences, as they standard allows the use of Market Flow	New

Appendix A

The following criteria are intended to assist the Reliability Coordinator in determining what level of TLR to call. However, the Reliability Coordinator has the discretion to choose any of these levels regardless of the criteria listed below, provided the Reliability Coordinator has reliability reasons to take such action.

Level	System Condition
TLR-1	• At least one Transmission Facility is expected to approach or exceed its SOL or IROL within 8 hours.
TLR-2	• At least one Transmission Facility is approaching or is at its SOL or IROL. o Analysis shows that holding new and increasing non-firm transactions and energy flows for the next hour can prevent exceeding this SOL or IROL.
TLR-3a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. o Analysis shows that full or partial curtailment or reallocation of non-firm transactions and energy flows can prevent exceeding this SOL and IROL.
TLR-3b	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. o Analysis shows that full or partial curtailment or reallocation of non-firm transactions and energy flows can prevent exceeding this SOL or IROLs .
TLR-4	• At least one Transmission Facility is expected to exceed its SOL or IROL. • Analysis shows that full curtailment of non-firm transactions and energy flows, or reconfiguration of the transmission system can prevent exceeding this SOL or IROL.
TLR-5a	• At least one Transmission Facility is expected to exceed its SOL or IROL when the next-hour's transactions start. • Analysis shows that either of the following sets of actions can prevent exceeding the SOL or IROL: o Full curtailment non-firm transactions and energy flows, or o Reconfiguration of the transmission system, and full or partial curtailment or reallocation of firm transactions and energy flows.
TLR-5b	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. • Analysis shows that either of the following sets of actions can prevent exceeding the SOL or IROL:

	o Full curtailment of non-firm transactions and energy flows, or o Reconfiguration of the transmission system, and full or partial curtailment or reallocation of firm transactions and energy flows. o

Implementation Plan for IRO-006-5 — Reliability Coordination — Transmission Loading Relief (TLR) and IRO-006-EI-1 — Loading Relief Procedure for the Eastern Interconnection

Summary

The NERC TLR Drafting Team has developed IRO-006-5 and IRO-006-EI-1 as iterative and incremental improvements to IRO-006-4. This is one of three phases of Project 2006-08. The first phase, the split of the IRO-006-3 and its associated Attachment 1 into NERC and NAESB standards, was completed and approved by the NERC Board of Trustees on October 23, 2007, and filed with regulatory authorities on December 21, 2007. The second phase, which is intended to address any needed modifications to the standards based on the PJM, MISO, and SPP waivers, is currently undergoing Field Testing. This implementation plan addressed the third phase, which is intended to improve the quality of the standards.

The drafting team has made significant revisions to the previous IRO-006-4 and Attachment 1:

1. Converted Attachment 1 into a standard solely for the Eastern Interconnection.
2. Transferred requirements from IRO-006 that were primarily focused on Eastern Interconnection practices to the Eastern interconnection TLR standard.
3. Clarified the roles of entities when responding to curtailment requests from other Interconnections.
4. Removed the requirement that entities comply with the INT standards, as it was redundant.
5. Restructured the Eastern Interconnection TLR standard (previously Attachment 1) to be clearer and specify reliability requirements.

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

Modified Standards

IRO-006-4, and associated Attachment 1, should be retired when IRO-006-5 and IRO-006-EI-1 become effective.

The definition of “Reallocation” should be removed from the Glossary when IRO-006-5 and IRO-006-EI-1 become effective.

The Regional Differences within IRO-006-4 should be retired when IRO-006-5 and IRO-006-EI-1 become effective.

Compliance with Standards

Once the standards become effective, the responsible entities identified in the applicability section of the standards must comply with the requirements. These include:

- Reliability Coordinators

Proposed Effective Date

The standards will become effective on the first day of the first calendar quarter that after the date the standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standards becomes effective on the first day of the first calendar quarter after the date the standards are approved by the NERC Board of Trustees.

Consideration of Comments on 1st Draft of IRO-006-5 and IRO-006-EI-1 — Project 2006-08

The Transmission Loading Relief Standard Drafting Team thanks all commenters who submitted comments on the 1st draft of standards IRO-006-5 — Reliability Coordination — Transmission Loading Relief and IRO-006-EI-1 — TLR Procedure for the Eastern Interconnection. These standards were posted for a 30-day public comment period from October 30, 2008 through December 1, 2008. Stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 12 sets of comments, including comments from more than 40 different people from approximately 30 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team has prepared a second draft of the standards. Comments that resulted in modifications to the standards are as follows:

- Commenters suggested that "reallocation" be footnoted to reference NAESB's business practices.
- Commenters proposed the definition of "Market Flow" be modified to replace the phrase "Market Flow Calculation Methodology" with more explicit language.
- Commenters expressed concerns with how the concepts of "interconnection wide" and/or "regional" standards were being addressed. In response, the SDT modified the approach to the standards and eliminated IRO-006-5 R1. IRO-006-EI-1 will continue to be treated as an Eastern Interconnection standard, and therefore apply to all Reliability Coordinators within the Eastern Interconnection. In order to comply with NERC's published numbering convention, the standard will be renamed as IRO-006-EAST-01.
- Commenters pointed out that TLR-0 was undefined. The level was added to the appendix.

On January 22, 2008, NERC staff met with FERC staff briefly to answer questions regarding the use of the Interchange Distribution Calculator and the TLR process. During these discussions, FERC staff suggested that as written, NERC standards related to TLR did not make clear that when experiencing an actual Interconnection Reliability Operating Limit (IROL) violation, the first responsibility of a Reliability Coordinator is to mitigate the IROL violation, then address the equity provisions of TLR. In other words, FERC staff opined that saying that a Reliability Coordinator was not to use TLR as the "sole remedy" to mitigate an IROL violation did not support the recommendation in the Blackout Report. FERC staff suggested that in order to support the recommendation in the Blackout Report, the standards should be clear that a Reliability Coordinator must initiate actions that can mitigate the IROL violation first, and then may follow with initiation or continuing management of the TLR process as appropriate. NERC staff brought the details of this conversation back to the TLR Drafting Team. The TLR Drafting Team discussed these comments, and made changes to IRO-006-EAST-1 R1 in response.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received can be viewed in their original format at:

http://www.nerc.com/filez/standards/Reliability-Coordination-Transmission-Loading-Relief.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Guy Zito	NPCC										✓

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
3.	Rick White	Northeast Utilities	NPCC	1
4.	Greg Campoli	New York Independent System Operator	NPCC	2
5.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
6.	Chris De Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Don Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
8.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
9.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Brian Evans-Mongeon	Utility Services, LLC	NPCC	6
13.	Mike Gildea	Constellation Energy	NPCC	6
14.	Lee Pedowicz	NPCC	NPCC	10

	Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10
2.	Jason Marshall	Midwest ISO Standards Stakeholders Collaborators		✓								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Cyrulewski	JDRJC Associates	RFC	8
2.	Kirit Shah	Ameren	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Denise Koehn	Bonneville Power Administration	✓		✓		✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Thomas Westbrook	Transmission Operational Analysis & Support	WECC	1
2.	Wesley Hutchison	Transmission Pre-Schedule & Real Time	WECC	1
3.	Timothy Loepker	Transmission Dispatch	WECC	1
4.	Joel Jenck	Power - Scheduling Coordination	WECC	5

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Roman Carter	Southern Company Transmission	✓									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Busbin	Southern Transmission	SERC	1
2.	Raymond Vice	Southern Transmission	SERC	1
3.	JT Wood	Southern Transmission	SERC	1
4.	Marc Butts	Southern Transmission	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Sam Ciccone	FirstEnergy	✓		✓	✓	✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dave Folk	FE	RFC	
2.	Doug Hohlbaugh	FE	RFC	

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Charles Yeung	IRC Standards Review Committee		✓								

Additional Member	Additional Organization	Region	Segment Selection

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

1.	Patrick Brown	PJM	RFC	2
2.	Jim Castle	New York ISO	NPCC	2
3.	Matt Goldberg	ISONE	NPCC	2
4.	Lourdes Estrada-Salinero	CAISO	WECC	2
5.	Anita Lee	AESO	WECC	2
6.	Steve Myers	ERCOT	ERCOT	2
7.	Bill Phillips	Midwest ISO	RFC	2
8.	Dan Rochester	IESO	NPCC	2

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Dan Rochester	IESO		✓								
8.	Thad Ness	American Electric Power (AEP)	✓		✓		✓	✓				
9.	Kathleen Goodman	ISO New England Inc		✓								
10.	Patrick Brown	PJM Interconnection										
11.	Paul Humberson, David Lemmons, Steve Rueckert, Donald Pape	WACM, Excel, WECC	✓									✓
12.	Jason Shaver	American Transmission Company	✓									
13.	Michael Brytowski	MRO										✓

	Additional Member	Additional Organization	Segment Selection
1.	Neal Balu	WPS	3,4,5,6
2.	Terry Bilke	MISO	2
3.	Carol Gerou	MP	1,3,5,6
4.	Jim Haigh	WAPA	1,6
5.	Charles Lawrence	ATC	1
6.	Ken Goldsmith	ALTW	4
7.	Pam Sordet	XEL	1,3,5,6
8.	Dave Rudolph	BEPC	1,3,5,6

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
9.	Eric Ruskamp	LES	1,3,5,6									
10.	Joseph Knight	GRE	1,3,5,6									
11.	Joe DePoorte	MGE	3,4,5,6									
12.	Larry Brusseau	MRO	10									

1. The drafting team has proposed to remove the NERC definition of Reallocation from the Glossary, as it is already defined in NAESB Business Practices. Do you believe this removal to be appropriate?

Summary Consideration: The majority of commenters support the elimination of this definition. This term is no longer used in any requirement. It is only used in Appendix A, which is intended to provide the Reliability Coordinator (RC) with a summary of system conditions, not require any specific action. In Appendix A, it is not capitalized to identify "reallocation" as a defined term. However, it has been footnoted to indicate that more information can be found within NAESB's business practices.

Organization	Question #1 Yes or No	Question #1 Comment
NPCC	No	NPCC participating members are not in agreement. A term used in a NERC standard should not be defined in a NAESB document. A joint NERC/NAESB glossary should be developed defining all terms in all standards. Until such time, the term must remain in the NERC glossary.
Response: The majority of commenters support the elimination of this definition. This term is no longer used in any requirement. It is only used in Appendix A, which is intended to provide the RC with a summary of system conditions, not require any specific action. In Appendix A, it is not identified as a defined term. However, it has been footnoted to indicate that more information can be found within NAESB's business practices. NERC and NAESB have discussed the possibility of creating a single joint glossary, but at this time, various logistical and regulatory constraints would make such a proposition difficult.		
ISO New England Inc	No	A term used in a NERC standard should not be defined in a NAESB document. A joint NERC/NAESB glossary should be developed defining all terms in all standards.
Response: The majority of commenters support the elimination of this definition. This term is no longer used in any requirement. It is only used in Appendix A, which is intended to provide the RC with a summary of system conditions, not require any specific action. In Appendix A, it is not identified as a defined term. However, it has been footnoted to indicate that more information can be found within NAESB's business practices. NERC and NAESB have discussed the possibility of creating a single joint glossary, but at this time, various logistical and regulatory constraints would make such a proposition difficult.		
American Transmission Company	No	ATC Operations prefers to see all definitions in one location, rather than searching multiple documents.
Response: NERC and NAESB have discussed the possibility of creating a single joint glossary, but at this time, various logistical and		

Organization	Question #1 Yes or No	Question #1 Comment
regulatory constraints would make such a proposition difficult.		
Midwest ISO Standards Stakeholders Collaborators	Yes	It is not clear how definitions in NAESB Business Practice apply to NERC standards. Do they apply because they are approved by FERC? To the extent this definition applies, we agree with it.
Response: NAESB definitions do not apply to NERC standards, and vice versa. The drafting team is proposing to eliminate the definition because the term is no longer used in any requirement. It is only used in Appendix A, which is intended to provide the RC with a summary of system conditions, not require any specific action. In Appendix A, it is not identified as a defined term. However, it has been footnoted to indicate that more information can be found within NAESB's business practices.		
IRC Standards Review Committee	Yes	It is not clear how definitions in NAESB Business Practice apply to NERC standards. Do they apply because they are approved by FERC? To the extent this definition applies, we agree with it.
Response: NAESB definitions do not apply to NERC standards, and vice versa. The drafting team is proposing to eliminate the definition because the term is no longer used in any requirement. It is only used in Appendix A, which is intended to provide the RC with a summary of system conditions, not require any specific action. In Appendix A, it is not identified as a defined term. However, it has been footnoted to indicate that more information can be found within NAESB's business practices.		
IESO	Yes	We agree that reallocation is a business practice and hence its definition is better placed in the NAESB Business Practices. Furthermore, to avoid inconsistencies terms should only be defined in one document. However, we recommend that a footnote is added in the NERC standards to refer to the appropriate NAESB documents for the definition of reallocation. In terms of the impact that such a change could eventually have on reliability, we recommend that NERC and NAESB develop the necessary controls such that, whenever implemented, reallocation provides the appropriate amount of transmission loading relief.
Response: The use of the term has been footnoted. NERC and NAESB will continue to coordinate their actions to ensure the missions of both organizations continue to be met.		
Bonneville Power Administration	Yes	
Southern Company Transmission	Yes	

Organization	Question #1 Yes or No	Question #1 Comment
FirstEnergy	Yes	
PJM Interconnection	Yes	
MRO NERS Standards Review Subcommittee	Yes	

2. The drafting team has proposed a new definition for inclusion in the NERC glossary:

   Market Flow: *the amount of energy flowing across a specified facility or set of facilities due to the operation of a market that has implemented a "Market Flow Calculation" methodology.*

   Do you agree with the proposed definitions in the standard?

Summary Consideration: While most commenters supported the definition, some requested more detail. The SDT has revised the definition to replace the phrase "Market Flow Calculation Methodology" with more explicit language as shown below:.

Market Flow: *the total amount of generation-to-load impact ~~of energy~~ flowing across a specified facility or set of facilities due to a market dispatch ~~the operation of a market that has implemented a "Market Flow Calculation" methodology~~.*

Organization	Yes or No	Question #2 Comment
FirstEnergy	Yes	While we agree the definition is needed, it relies on the term "Market Flow Calculation" which is not a NERC Glossary Term and should also be defined in this standard.
Response: The SDT has revised the definition to replace the phrase "Market Flow Calculation Methodology" with more explicit language.		
IESO	Yes	While we agree that a market flow definition should be listed in the NERC glossary, we are concerned about the clarity of this definition. We think that the SDT should provide a market flow definition that is unequivocal and that does not allow entities to reclassify the components that constitute a market flow in manner that diminishes their obligation to provide transmission loading relief.
Response: The obligation for those markets that calculate Market Flow to provide Transmission Loading Relief is covered by requirements within the standard, and does not need to be restated in this definition.		
MRO NERS Standards Review Subcommittee	Yes	** what is 'Market Flow Methodology"?
Response: The SDT has revised the definition to replace the phrase "Market Flow Calculation Methodology" with more explicit language.		
NPCC	Yes	

Organization	Yes or No	Question #2 Comment
Midwest ISO Standards Stakeholders Collaborators	Yes	
Bonneville Power Administration	Yes	
Southern Company Transmission	Yes	
IRC Standards Review Committee	Yes	
AEP	Yes	
ISO New England Inc	Yes	
PJM Interconnection	Yes	
American Transmission Company	Yes	

3. The drafting team has moved or eliminated three of the requirements originally in IRO-006-4:

- The drafting team eliminated IRO-006-4 R2, which stated "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."
- The drafting team moved IRO-006-4 R3, which stated "Each Reliability Coordinator with a relief obligation from an Interconnection-wide procedure 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 of the local procedure from the ERO." These concepts were incorporated into the new IRO-006-EI-1.
- The drafting team eliminated IRO-006-4 R5, which stated "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." This language was redundant with the INT standards themselves.

Do you believe these modifications are appropriate?

Summary Consideration: Most commenters believe the changes to be appropriate. One entity expressed concern about how the concept of regional standards was being addressed. In response, the SDT modified the approach to the standards and eliminated IRO-006-5 R1. IRO-006-EI-1 will continue to be treated as an Eastern Interconnection standard, and therefore apply to all Reliability Coordinators within the Eastern Interconnection. In order to comply with NERC's published numbering convention, the standard will be renamed as IRO-006-EAST-01.

Organization	Question #3 Yes or No	Question #3 Comment
ISO New England Inc	No	Although the ability for NERC to develop interconnection-wide standards is clearly adopted in the Rules of Procedure and Standards Development Procedure, we believe that NERC/ERO Standards should be either continent-wide or regional. Developing interconnection-wide standards adds complexity to the stakeholders and the compliance programs, and will result in a greater number of standards. In addition, the proposed numbering for IRO-006-EI-1 is an inconsistent standard numbering convention, and will create difficulties with compliance based software applications. Also, With the deletion of R3 and the wording of the new IRO-006-5 R1, it is unclear how/if all entities within an Interconnection are required to respond to a request for relief under an Interconnection Wide procedure. The confusion arises from the fact that R1 states the 'RC that USES an Interconnection-wide congestion management procedure shall use the procedure for its Interconnection'. If, for example, an RC in the Eastern Interconnect does not USE an Interconnection Wide congestion management process, that RC would not be required to follow the request for curtailment under the Interconnection Wide procedure.

Organization	Question #3 Yes or No	Question #3 Comment
Response: The SDT has modified the approach to the standards and eliminated IRO-006-5 R1. IRO-006-EI-1 will continue to be treated as an Eastern Interconnection standard, and therefore apply to all RCs within the Eastern Interconnection. In order to comply with NERC's published numbering convention, the standard will be renamed as IRO-006-EAST-01.		
NPCC	Yes	
Midwest ISO Standards Stakeholders Collaborators	Yes	
Bonneville Power Administration	Yes	
Southern Company Transmission	Yes	
FirstEnergy	Yes	
IRC Standards Review Committee	Yes	
IESO	Yes	
AEP	Yes	
PJM Interconnection	Yes	
WACM, Excel, WECC	Yes	
American Transmission Company	Yes	
MRO NERS Standards Review Subcommittee	Yes	

4. The SDT has proposed removing the Regional Differences for MISO, PJM, and SPP, as the language within IRO-006-EI-1 incorporates the concept of Market Flow. Do you agree that these Regional Differences can be removed?

Summary Consideration: None of the respondents disagreed with the removal of these Regional Differences.

Organization	Question #4 Yes or No	Question #4 Comment
Midwest ISO Standards Stakeholders Collaborators	Yes	
Southern Company Transmission	Yes	
FirstEnergy	Yes	
IRC Standards Review Committee	Yes	
IESO	Yes	
AEP	Yes	
PJM Interconnection	Yes	
MRO NERS Standards Review Subcommittee	Yes	

5. The drafting team has converted Attachment 1 to a separate standard that is posted with this comment form (IRO-006-EI-1). Do you believe this is appropriate?

Summary Consideration: Two entities opposed the creation of an Interconnection Wide standard, although both agreed that NERC's Rules of Procedures allow for such standards to be developed. IRO-006-EI-1 will continue to be treated as an Eastern Interconnection standard, and therefore apply to all RCs within the Eastern Interconnection. In order to comply with NERC's published numbering convention, the standard will be renamed as IRO-006-EAST -01.

Organization	Question #5 Yes or No	Question #5 Comment
NPCC	No	See response to question 6.
Response: Please see our response in Question 6.		
ISO New England Inc	No	Although the ability for NERC to develop interconnection-wide standards is clearly adopted in the Rules of Procedure and Standards Development Procedure, we believe that NERC/ERO Standards should be either continent-wide or regional. Developing interconnection-wide standards adds complexity to the stakeholders and the compliance programs, and will result in a greater number of standards. In addition, the proposed numbering for IRO-006-EI-1 is an inconsistent standard numbering convention, and will create difficulties with compliance based software applications.
Response: The SDT does not agree that standards should only be regional or continent-wide, and as indicated by the commenter, NERC's Rules of Procedure allow the development of such standards. IRO-006-EI-1 will continue to be treated as an Eastern Interconnection standard, and therefore apply to all RCs within the Eastern interconnection. In order to comply with NERC's published numbering convention, the standard will be renamed as IRO-006-EAST-01.		
Midwest ISO Standards Stakeholders Collaborators	Yes	In general, we do not support standards that are in essence procedures. However, we do believe the drafting team has pared down the true reliability requirements out of attachment one. Given this paring down of attachment one and the importance of the TLR procedure, we can support this standard.
Response: Thank you for your supportive comment.		
IRC Standards Review Committee	Yes	In general, the IRC SRC does not support standards that are in essence procedures. However, we do believe the drafting team has pared down the true reliability requirements out of attachment one. Given this paring down of attachment one and the importance of the TLR procedure, the IRC SRC can support this standard.

Organization	Question #5 Yes or No	Question #5 Comment
Response: Thank you for your supportive comment.		
Southern Company Transmission	Yes	
FirstEnergy	Yes	
IESO	Yes	
AEP	Yes	
PJM Interconnection	Yes	
WACM, Excel, WECC	Yes	
MRO NERS Standards Review Subcommittee	Yes	

6. The drafting team has proposed that Attachment 1 be treated as a standard for the Eastern Interconnection (IRO-006-EI-1). Alternatively, the standard may be treated as a continent-wide standard (IRO-017) that is applicable only to entities in the Eastern Interconnection. Do you prefer one approach over the other?

Summary Consideration: Seven of the thirteen respondents supported the EI naming convention, while four of the thirteen preferred the alternate approach. In order to comply with NERC's published numbering convention, the standard will be renamed as IRO-006-EAST-01.13 responses.

Organization	IRO-006-EI-1	IRO-017-1	Question #6 Comment
WACM, Excel, WECC			No preference as to IRO-006-EI-1 or IRO-017, but agree treatment identifying it is the Eastern Interconnection process and not a continent-wide process is correct.
Response: Thank you for your supportive comment.			
NPCC		X	Although the ability for NERC to develop interconnection-wide standards is clearly adopted in the Rules of Procedure and Standards Development Procedure, NPCC participating members believe that NERC/ERO Standards should be either continent-wide or regional. Developing interconnection-wide standards adds complexity and potential confusion to the stakeholders and the compliance programs, and will result in a greater number of standards. In addition, the proposed numbering for IRO-006-EI-1 is an inconsistent standard numbering convention, and will create difficulties with compliance based software applications.
Response: The SDT does not agree that standards should only be regional or continent-wide, and as indicated by the commenter, NERC's rules of procedure allow the development of such standards. IRO-006-EI-1 will continue to be treated as an Eastern Interconnection standard, and therefore apply to all RCs within the Eastern interconnection. In order to comply with NERC's published numbering convention, the standard will be renamed as IRO-006-EAST-01.			
ISO New England Inc		X	Although the ability for NERC to develop interconnection-wide standards is clearly adopted in the Rules of Procedure and Standards Development Procedure, we believe that NERC/ERO Standards should be either continent-wide or regional. Developing interconnection-wide standards adds complexity to the stakeholders and the compliance programs, and will result in a greater number of standards. In addition, the proposed numbering for IRO-006-EI-1 is an inconsistent standard numbering convention, and will create difficulties with compliance based software applications.
Response: In order to comply with NERC's published numbering convention, the standard will be renamed as IRO-006-EAST-01.			

Organization	IRO-006-EI-1	IRO-017-1	Question #6 Comment
MRO NERS Standards Review Subcommittee		X	The MRO believes that naming the standard IRO-017-1 stays consistant with the NERC standard naming convention and does not add another element to the standards naming.
Response: In order to comply with NERC's published numbering convention, the standard will be renamed as IRO-006-EAST-01.			
American Transmission Company		X	
FirstEnergy	X		It may be better to easily identify the Eastern Interconnection requirements with the "EI" designation since WECC made their numbering system unique (WECC-IRO-STD-006-0).
Response: In order to comply with NERC's published numbering convention, the standard will be renamed as IRO-006-EAST-01.			
AEP	X		AEP supports the use of IRO-006-EI-1, but is not strongly opposed to the use of IRO-017-1.
Response: Thank you for your supportive comment.			
Midwest ISO Standards Stakeholders Collaborators	X		
Southern Company Transmission	X		
IRC Standards Review Committee	X		
IESO	X		
PJM Interconnection	X		

7. The drafting team has identified a concern related to compliance with IRO-006-EI-1 and the availability of the IDC or similar technology. To address this, the SDT is considering adding the following language to the IRO-006-5:

   R1. A Reliability Coordinator desiring to utilize an Interconnection-wide congestion management procedure shall utilize the appropriate procedure below based on the region in which they oversee reliability, provided the necessary tools to support the procedure are available and in working order:

   Do you believe this or similar language is appropriate and necessary?

Summary Consideration: Following further discussion, the SDT believes that the current draft standard as written allows for sufficient flexibility to ensure that Internet outages, software problems, or hardware failures will not result in situations in which the NERC requirements cannot be met.

Organization	Question #7 Yes or No	Question #7 Comment
Midwest ISO Standards Stakeholders Collaborators	No	This language is not appropriate. Because an RC can't relay on the use of TLR to mitigate an IROL, the RC must always have alternative methods to available to mitigate IROLs. Thus, the availability of the IDC is not truly relevant to reliability.
Response: Following further discussion, the SDT believes that the current draft standard as written allows for sufficient flexibility to ensure that Internet outages, software problems, or hardware failures will not result in situations in which the NERC requirements cannot be met. The proposed language has not been added.		
FirstEnergy	No	If the "necessary tools to support the procedure are" not in service or available, then the procedure and/or standard should be retired at the same time that the tools are no longer available. Therefore this requirement is unnecessary and inappropriate for a reliability standard.
Response: Following further discussion, the SDT believes that the current draft standard as written allows for sufficient flexibility to ensure that Internet outages, software problems, or hardware failures will not result in situations in which the NERC requirements cannot be met. The proposed language has not been added.		
IRC Standards Review Committee	No	All NERC standards implicitly require that the hardware and software associated with effecting a response to the respective requirement's is operational. There is no need to even include the provision about the availability of the support tools.
Response: Following further discussion, the SDT believes that the current draft standard as written allows for sufficient flexibility to ensure that		

Organization	Question #7 Yes or No	Question #7 Comment
Internet outages, software problems, or hardware failures will not result in situations in which the NERC requirements cannot be met. The proposed language has not been added.		
IESO	No	We disagree with the wording and suggest the latter part of the sentence be deleted (i.e. ", provided the necessary tools to support the procedure are available and in working order"). We believe that a Reliability Coordinator that chooses to utilize an Interconnection-wide congestion management procedure should make sure that it has the necessary tools to support the procedure and they are available and in working order. Furthermore, tools unavailability should not preclude the implementation of an interconnection-wide congestion management procedure. Besides TLR, system operators can access other mechanisms to mitigate IROL violations, such as reconfiguration, redispatch, load shedding etc.
Response: Following further discussion, the SDT believes that the current draft standard as written allows for sufficient flexibility to ensure that Internet outages, software problems, or hardware failures will not result in situations in which the NERC requirements cannot be met. The proposed language has not been added.		
ISO New England Inc	No	The last sentence "provided the necessary tools to support the procedure are available and in working order" is not needed.
Response: Following further discussion, the SDT believes that the current draft standard as written allows for sufficient flexibility to ensure that Internet outages, software problems, or hardware failures will not result in situations in which the NERC requirements cannot be met. The proposed language has not been added.		
PJM Interconnection	No	The availability of a software tool should not dictate whether or not the RC takes action to alleviate a reliability issue. If the IDC tools are not available, or not properly functioning in real-time, the RC should not be absolved from the responsibility to initiate a good faith effort to comply with the spirit of the TLR procedures. The RC should not be considered non-compliant if the software is not functioning and, despite a good faith effort, the RC could not achieve full compliance.
Response: Following further discussion, the SDT believes that the current draft standard as written allows for sufficient flexibility to ensure that Internet outages, software problems, or hardware failures will not result in situations in which the NERC requirements cannot be met. The proposed language has not been added.		
American Transmission Company	No	
NPCC	Yes	Remove the wording "provided the necessary tools to support the procedure are available and in

Organization	Question #7 Yes or No	Question #7 Comment
		working order:" The RC must have the tools to support the procedure.
Response: Following further discussion, the SDT believes that the current draft standard as written allows for sufficient flexibility to ensure that Internet outages, software problems, or hardware failures will not result in situations in which the NERC requirements cannot be met. The proposed language has not been added.		
AEP	Yes	- Our "yes" depends upon what this statement means... We answer "yes" - if you mean that the RC cannot provide an Interconnection-wide congestion management procedure without the using the IDC or similar technology. We answer "no" - if you mean you don't
Response: Following further discussion, the SDT believes that the current draft standard as written allows for sufficient flexibility to ensure that Internet outages, software problems, or hardware failures will not result in situations in which the NERC requirements cannot be met. The proposed language has not been added.		
MRO NERS Standards Review Subcommittee	Yes	
Southern Company Transmission	Yes	

8. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

Summary Consideration: No entities commented that they were aware of any conflicts.

Organization	Question #8 Yes or No	Question #8 Comment
NPCC	No	
Midwest ISO Standards Stakeholders Collaborators	No	
Bonneville Power Administration	No	
Southern Company Transmission	No	
FirstEnergy	No	
IRC Standards Review Committee	No	
IESO	No	
AEP		
ISO New England Inc	No	
PJM Interconnection	No	
WACM, Excel, WECC		
American Transmission Company	No	
MRO NERS Standards Review Subcommittee	No	

9. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standards.

Summary Consideration: Some entities expressed concern with the phrasing of IRO-006-EI (EAST) R1. The SDT has chosen not to modify IRO-006-EI R1, as it is consistent with language currently within IRO-006-4.

One entity suggested that IRO-006-EI (EAST) R1 might be redundant with IRO-005 R17. The SDT explained that IRO-005 R17 applies to all actions, and leaves it up to the RC to determine if the actions being taken are sufficient or not. IRO-006-EI (EAST) R1 specifically applies to TLR, and prohibits the use of TLR as the sole tool to mitigate an IROL violation.

One entity expressed confusion regarding the difference between IRO-006-EI (EAST) R4.2 and R4.3. The SDT explained that R4.2 is intended to address situations where an entity wishes to use an alternate procedure on an ongoing basis, NOT one that is necessarily occurring in real-time. The standard communicates this through the use of the phrase “pre-approved.” If a real-time alternative was developed, it would fall as described under R4.3.

One entity expressed concern that IRO-006-EI (EAST) R4 might create a situation where an RC was forced to violate a standard. The SDT explained that R4.3.2 implies that the initiating RC will respond to alternate actions proposed by the responding RC. Absent a response or a concurrence, the responding RC has met its obligation, even if it does not implement any of the actions in R4.

One entity pointed out that TLR-0 was undefined. The level was added to the appendix.

Some entities expressed general concerns with the relevance of the standards to WECC, and a specific concern with a reference in IRO-006-5 R1. The SDT has elected to modify the standard to eliminate IRO-006-5 R1, which we believe will address the commenters’ concerns. IRO-006-5 R2 has been modified to include Transmission Operators and Balancing Authorities, which the SDT believes will further support the WECC practices. The SDT also pointed out that IRO-006-EI (EAST) is intended to apply only to the Eastern Interconnection.

Organization	Question #9 Comment
Bonneville Power Administration	These revisions are quite specific to the methods and procedures of the Eastern Interconnection. Things are done a little differently in the West, therefore choosing not to comment on those specific questions.
Response: The SDT agrees. IRO-006-EI (EAST) is intended only to apply within the Eastern Interconnection. IRO-006-5 has been modified to address differences in implementation between the various Interconnections.	
FirstEnergy	IRO-006-EI-1 R1 should be revised to state, "When responding to an IROL violation, each Reliability Coordinator shall implement other actions, including reconfiguration, redispatch, use of demand-side

Organization	Question #9 Comment
	management, or load shedding in conjunction with the initiation of the Eastern Interconnection TLR procedure." In the standards the assumption should be that the operator is responding to actual situations unless stated otherwise. The reliability standards represent the minimum requirements therefore the term "but not limited to" is redundant and unnecessary. **Response:** The SDT has chosen not to modify IRO-006-EI R1, as it is consistent with language currently within IRO-006-4. IRO-006-EI-1 R2.2 should be revised to state, "A plan of action, based on the TLR level chosen." If the RC is in a TLR, they should be leading the activities and not merely proposing actions. **Response:** The SDT believes that language as written is appropriate. In IRO-006-EI-1 R3 the phrase "a proposal for actions to take" should be replaced with the phrase "a plan of action." In IRO-006-EI-1 R3 the phrase "proposed actions to take" should be replaced with the phrase "action plan." **Response:** The SDT believes that language as written is appropriate. In IRO-006-EI-1 R3.2 and R3.3 the phrase "proposed actions" should be replaced with the phrase "action plan." **Response:** The SDT believes that language as written is appropriate. In IRO-006-EI-1 R3.2, R3.3, R3.3.1, R3.3.2, R3.3.3, and R3.3.4 the term "proposed" should be replaced with the phrase "planned." **Response:** The SDT believes that language as written is appropriate. IRO-006-EI-1 R4.2 - We suggest removing R4.2. We do not agree that the ERO should have a role in a reliability standard requirement. This requirement should be removed because it does not place responsibilities (and for that matter cannot since they are not a user, operator or owner of the BES) on the ERO to act in sufficient time to approve an alternate mitigation procedure. Any delay on the part of the ERO could adversely impact the reliability of the BES. Also, even if the ERO was appropriate in the standard, R4.2 is not necessary since R4.3 already covers alternate actions that can be taken in lieu of R4.1.

Organization	Question #9 Comment
	Response: R4.2 is intended to address situations where an entity wishes to use an alternate procedure on an ongoing basis, NOT one that is necessarily occurring in real-time. The standard communicates this through the use of the phrase "pre-approved." If a real-time alternative was developed, it would fall as described under R4.3.
Response: Please see in-line responses.	
PJM Interconnection	R1. The first sentence should be reworded to say what actions should be taken instead of what should not be done. Current wording; R1. The Reliability Coordinator shall not use the Eastern Interconnection TLR procedure alone to mitigate an actual IROL violation. Recommended word change to make it a proactive requirement;R1. When responding to an actual IROL violation, each Reliability Coordinator shall implement supplementary mitigation actions prior to or in conjunction with the initiation of this TLR procedure. Such actions include, but are not limited to, the following: reconfiguration, redispatch, use of demand-side management, load shedding. **Response:** The SDT has chosen not to modify IRO-006-EI R1, as it is consistent with language currently within IRO-006-4. Two additional comments regarding R1: This requirement is similar to the Requirement R17 in IRO-005. The SDT should consider revising R1 of this standard or R17 of IRO-005 to address the need in one standard instead of splitting it into two separate requirements. **Response:** IRO-005 R17 applies to all actions, and leaves it up to the RC to determine if the actions being taken are sufficient or not. IRO-006-EI (EAST) R1 specifically applies to TLR, and prohibits the use of TLR as the sole tool to mitigate an IROL violation. Also the SDT needs to develop language that requires the mitigation actions external to the TLR procedures be bonafide mitigation attempts. **Response:** The SDT is uncertain what is being requested. R 4.3.2. The SDT should discuss the appropriateness of the "and" conditions throughout R 4.3. R 4.3.2 should be strengthened to accommodate alternatives to the TLR procedure. For example, if an action contained in the TLR procedure would have an adverse consequence on the network but, for whatever reason, concurrence from the RC calling the TLR isn't obtained, the only options available to the RC requesting an alternative are 1) to be non-compliant or 2) implement a change that has a negative impact on system reliability.

Organization	Question #9 Comment
	Response: R4.3.2 implies that the initiating RC will respond to alternate actions proposed by the responding RC. Absent a response or a concurrence, the responding RC has met its obligation, even if it does not implement any of the actions in R4. Appendix A- The standard references TLR level 0, which is not included in the appendix. **Response:** The SDT has modified the appendix to address this issue.
Response: Please see in-line responses.	
WACM, Excel, WECC	WECC believes that bullet 2 of R1 should reference the WECC Qualified Path Unscheduled Flow Relief Plan and not the WECC interim Tier 1 regional reliability standard. RCs in the West do not receive requests for curtailment. The WECC Qualified Path Unscheduled Flow Relief Procedures identifies entities receiving the schedule as the entity that must implement curtailments. We question whether RCs can actually curtail or reload transactions (normally a TOP function in the west). WECC RCs do not do this. We believe that RC's in the East are typically BA operators also. WECC's are not. We believe that the language in the current standard reflects an Eastern Interconnection bias towards transmission loading relief and would need to be modified to recognize the different process in the West before it could become a continent-wide standard.
Response: The SDT has elected to modify the standard to eliminate IRO-006-5 R1, which we believe will address the commenters' concerns. IRO-006-5 R2 has been modified to include Transmission operators and Balancing Authorities, which the SDT believes will further support the WECC practices. Note that IRO-006-EI (EAST) is intended to apply only to the Eastern Interconnection.	

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 the SAR and assembled a drafting team on December 5, 2006.
2. The revisions to IRO-006 to transfer business practice content to NAESB were approved as IRO-006-4 by the Board of Trustees on October 23, 2007.
3. The SDT has developed a first draft for industry consideration and posted it for comments from October 30, 2008 to December 1, 2008.
4. The SDT has developed this second draft for industry consideration.

Description of Current Draft:

This is the second draft of the proposed standard posted for stakeholder comments.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Respond to Comments (Draft 2).	June 26, 2009
2. Posting for 30-day Pre-Ballot Review.	June 26, 2009
3. Initial Ballot.	July 27, 2009
4. Respond to comments.	September 10, 2009
5. Recirculation ballot.	September 10, 2009
6. Board adoption.	October 2009

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.

None.

A. Introduction

1. **Title:** **Reliability Coordination — Transmission Loading Relief (TLR)**
2. **Number:** **IRO-006-5**
3. **Purpose:** To provide Interconnection-wide transmission loading relief procedures that can be used to prevent or manage potential or actual SOL and IROL violations to maintain reliability of the bulk electric system.
4. **Applicability:**
   4.1. Reliability Coordinator.
   4.2. Balancing Authority.
   4.3. Transmission Operator.
5. **Proposed Effective Date:** First day of the first calendar quarter ~~that after~~following the date this standard and IRO-006-EAST-1 are both ~~is~~ approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard and IRO-006-EAST-1 are both~~is~~ approved by the NERC Board of Trustees.

B. Requirements

~~Each Reliability Coordinator that uses an Interconnection-wide congestion management procedure shall use the procedure for its Interconnection identified below: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]~~

~~The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection provided in IRO-006-5-EI.~~

~~The Interconnection-wide transmission loading relief procedure for use in the Western Interconnection isWECC-IRO-STD-006-0 provided at: ftp://www.nerc.com/pub/sys/all_updl/standards/rrs/IRO-STD-006-0_17Jan07.pdf.~~

~~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~~

R1. Each Reliability Coordinator, Balancing Authority, or Transmission Operator that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (~~listed in R1~~such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) ~~above~~ from any Reliability Coordinator~~, Balancing Authority, or Transmission Operator~~ ~~Reliability Coordinator~~ in another Interconnection (or Balancing Authority or Transmission Operator, as appropriate for the neighboring Interconnection) to curtail or reload an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provide~~d~~s a reliability reason that ~~implementing~~it cannot comply with the request ~~will not adversely affect reliabilityis within the bounds of reliable operation~~. ~~.~~ [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence (such as logs, voice recordings, Tag histories, and studies) that, when a request to curtail or reload an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure was made from another Reliability Coordinator, Balancing Authority, or Transmission Operator, it complied with the request or provided an identified reliability reason that it could not comply with the request.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Reliability Coordinator, Balancing Authority, and Transmission Operator shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator, Balancing Authority, and Transmission Operator shall maintain evidence to show compliance with R1 for the most recent ~~three~~ ~~eighteen~~twelve calendar ~~years~~ months plus the current ~~year~~month.
- If a Reliability Coordinator, Balancing Authority, or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				The applicable entity received a request to curtail or reload an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority, or Transmission Operator, but the entity ~~recipient~~ neither ~~1.)~~ complied with the request, nor ~~2.)~~ provided a reliability reason that it could not ~~prevented their compliance~~comply with the request.

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~~**Reallocation:** The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.~~ (To be retired.)

Market Flow: the total amount of generation-to-load impact~~f energy~~ flowing across a specified facility or set of facilities due to a market dispatch. ~~the operation of a market that has implemented a "Market Flow Calculation" methodology.~~

A. Introduction

1. **Title: Transmission Loading Relief Procedure for the Eastern Interconnection**

2. **Number:** IRO-006-~~EI~~EAST-1

3. **Purpose:** To provide an Interconnection-wide transmission loading relief procedure (TLR) for the Eastern Interconnection that can be used to prevent and/or mitigate potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) ~~violations~~ exceedances to maintain reliability of the ~~bulk~~ Bulk ~~electric~~ Electric ~~system~~System (BES).

4. **Applicability:**

   4.1. Reliability Coordinators in the Eastern Interconnection.

5. **Effective Date:** First day of the first calendar quarter ~~that~~ after the date this standard and IRO-006-5 are both~~is~~ approved by applicable regulatory authorities~~,~~; or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard and IRO-006-5 are both~~is~~ approved by the NERC Board of Trustees.

B. Requirements

R1. The Reliability Coordinator shall not use the Eastern Interconnection TLR procedure alone to mitigate an ~~actual~~ IROL ~~violation~~exceedance. When acting or directing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_v~~responding to an actual IROL violation~~, each Reliability Coordinator shall ~~implement~~ initiate other more effective actions prior to or in conjunction with the initiation ~~or continuing management~~ of this TLR procedure (or continuing management of this procedure if already initiated), including, but not limited to, the following: reconfiguration, redispatch, use of demand-side management, and load shedding.~~-~~ [*Violation Risk Factor: ~~Medium~~High*] [*Time Horizon: Real-time Operations*]

R2. When initiating the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL ~~violation~~exceedance, and at least every clock hour after initiation, up to and including the hour when the TLR level has been identified as TLR Level 0, the Reliability Coordinator shall identify: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

R2.1. The TLR level in accordance with the criteria in Appendix A, and

R2.2. A ~~proposal for~~list of actions to take, based on the TLR level chosen.

R3. Upon the identification of the TLR level and a ~~proposal for~~list of actions to take based on the TLR level chosen, the Reliability Coordinator initiating this TLR procedure shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

R3.1. Notify all Reliability Coordinators in the Eastern Interconnection of the identified TLR level

R3.2. Communicate the ~~proposed~~ list of actions to take to:

R3.2.1. All Reliability Coordinators in the Eastern Interconnection, and

R3.2.2. Those Reliability Coordinators in other Interconnections responsible for curtailing or reloading Interchange Transactions crossing Interconnection boundaries identified in the ~~proposed~~ list of actions.

R3.3. Request that the following entities implement the ~~proposed~~ actions identified in Requirement R2.2: ~~[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]~~

~~**R3.3.1.**~~Each Reliability Coordinator associated with a Sink Balancing Authority in the Eastern Interconnection for which Interchange Transactions are ~~proposed for~~to be curtailed~~ment~~ or reloaded~~ing~~

R3.3.1.

R3.3.2. Each Reliability Coordinator~~s~~ associated with a Balancing Authority in the Eastern Interconnection for which Network Integration Transmission Service or Native Load is ~~proposed for~~to be curtailed~~ment~~ or reloaded~~ing~~

~~**R3.3.3.**~~Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which ~~proposed~~ its ~~to provide~~ Market Flow is to be curtailed ~~ment~~ or reloaded~~ing~~.

R3.3.3.

R3.3.4. Each Reliability Coordinator~~s~~ associated with a Balancing Authority in the Eastern Interconnection operating a DC-tie for an Interchange Transaction sinking outside the Eastern Interconnection and crossing an interconnection boundary with an Interchange Transaction to be ~~proposed for~~ curtailed~~ment~~ or reloaded~~ing~~.

R4. Each Reliability Coordinator in the Eastern Interconnection that re~~sponds to~~ceives a request as described in Requirement R3.3. shall comply with the request by taking one or more of the following three sets of actions: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

~~R4.1.~~1) Implement the communicated actions requested by the issuing Reliability Coordinator as follows:

- Direct its Balancing Authorities to implement the Interchange Transaction schedule change requests.
- Direct its Balancing Authorities to provide the Network Integrated Transmission Service and Native Load schedule changes for which the Balancing Authorities are responsible.
- Direct its Balancing Authorities to provide the Market Flow schedule changes for which the Balancing Authorities are responsible.

~~R4.2.~~2) Implement a procedure pre-approved by the ERO for use by the responding Reliability Coordinator in lieu of implementing some or all of the requested actions in the first set under Requirement R4~~R4.1~~, provided that its implementation is expected to prevent or mitigate the SOL or IROL ~~violation~~ exceedance with the same or greater effect than the actions not implemented in ~~R4.1~~ the first set of actions under Requirement R4.

~~R4.3.~~3) Implement alternate actions to those in ~~R4.1 or R4.2~~the first two sets of actions under Requirement R4 provided that:

~~R4.3.1.~~Analysis shows that some or all of the actions in ~~R4.1~~the first set of actions under Requirement R4 or ~~R4.2~~the second set of actions under Requirement R4 will result in a reliability concern or will be ineffective, and

- The alternate actions have been agreed to by the initiating Reliability Coordinator, and

- ~~P4.3.3.~~ Analysis shows that the alternate actions will not adversely affect reliability.

R5. Each Reliability Coordinator that responds to a TLR event shall acknowledge to the initiating Reliability Coordinator the actions it will take pursuant to Requirement R4 as soon as possible but not more than ~~within thirty~~ ten minutes ~~of~~ after receiving the request. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

C. Measures

M1. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that when acting or directing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_v~~experiencing an actual IROL, the Eastern Interconnection TLR procedure was not the sole remedy used to mitigate the violation~~, the Eastern Interconnection TLR procedure was not used alone to mitigate an IROL exceedance, and ~~,~~other more effective actions ~~actions other than TLR~~ were initiated ~~to mitigate the violation~~ prior to or in conjunction with the initiation or continuing management of the TLR procedure. (R1)~~.~~

M2. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that at the time it initiated the Eastern Interconnection TLR procedure, and at least every clock hour after initiation, up to and including the hour when the TLR level was identified as TLR Level 0, the Reliability Coordinator identified both the TLR Level in accordance with Appendix A and a list of ~~proposal for~~ actions to take based on the TLR level chosen. (R2)~~.~~

M3. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that once it identified a TLR level and ~~a proposal for~~for a list of ~~proposed~~ actions to take, it:

1.) ~~communicated the TLR Level to n~~Notified all Reliability Coordinators in the Eastern ~~i~~Interconnection of the TLR Level,

2.) ~~c~~Communicated the list of ~~proposed~~ actions to all Reliability Coordinators in the Eastern I~~i~~nterconnection and those Reliability Coordinators in other Interconnections responsible for curtailing or reloading Interchange

Transactions crossing Interconnection boundaries identified in the list of ~~proposed~~ actions, and

3.) ~~r~~Requested the Reliability Coordinators identified in the Requirement to implement the ~~proposed~~ actions. (R3)~~.~~

M4. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that upon receipt of a request to implement proposed actions as described in Requirement R3, the Re~~a~~liability Coordinator did one or more of the following:

1.) I~~i~~mplemented the requested actions,

2.) ~~i~~Implemented an alternative procedure that had been pre-approved by the ERO in lieu of some or all of the actions requested with equal or greater effect than the request actions not being implemented,

3.) ~~i~~Implemented alternate actions~~, provided that~~ based on analysis which showed that some or all of the actions in 1 or 2 would have resulted in a reliability concern or would have been ineffective, the alternate actions were agreed to by the initiating Reliability Coordinator, and analysis showed that the alternate actions would not adversely affect reliability. (R4)~~.~~

M5. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that within ten ~~thirty~~ minutes of receiving a request to implement actions pursuant to the implementation of the Eastern Interconnection TLR procedure, it acknowledged to the initiating Reliability Coordinator the actions it ~~took~~will take in response to their request. (R5)

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

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

- The Reliability Coordinator shall maintain evidence to show compliance with Requirements R1, R2, R3, R4, and R5 for the past 12 months plus the current month~~most recent three calendar years plus the current year~~.
- If a Reliability Coordinator~~, Balancing Authority, or Transmission Operator~~ is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

~~1.~~3. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				The Reliability Coordinator used the Eastern Interconnection TLR procedure alone to mitigate an IROL exceedance. OR When acting or directing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_v, the Reliability Coordinator did not initiate other more effective actions prior to or in conjunction with the initiation of this TLR procedure (or continuing management of this procedure if already initiated).~~The Reliability Coordinator experiencinged an actual IROL violation and did not initiate actions other than TLR to mitigate the violation prior to the initiation or continuing management of the TLR procedureutilized the Eastern Interconnection TLR procedure as the sole remedy to mitigate the violation.~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	The Reliability Coordinator initiating the Eastern ~~i~~Interconnection TLR procedure missed identifying the TLR Level in accordance with Appendix A and/or a list of actions to take based on the TLR level chosen for one clock hour during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.~~,~~	The Reliability Coordinator initiating the Eastern interconnection TLR procedure missed identifying the TLR Level in accordance with Appendix A and/or a list of actions to take based on the TLR level chosen for two clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0~~,~~.	The Reliability Coordinator initiating the Eastern interconnection TLR procedure missed identifying the TLR Level in accordance with Appendix A and/or a list of actions to take based on the TLR level chosen for three clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.~~,~~	The Reliability Coordinator initiating the Eastern interconnection TLR procedure missed identifying the TLR Level in accordance with Appendix A and/or a list of actions to take based on the TLR level chosen for four or more clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0~~,~~.~~The Reliability Coordinator initiating the Eastern interconnection TLR procedure did not, at the time of initiation and at least every clock hour after initiation, up to and including the hour when the TLR level was identified as TLR Level 0, identify the TLR Level in accordance with Appendix A and identify a proposal for actions to take based on the TLR level chosen.~~
R3	The initiating Reliability Coordinator did not ~~communicate the TLR level~~notify ~~to~~ one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level (R3.1)	Not applicable.	The initiating Reliability Coordinator did not communicate the list of actions to one or more of the required Reliability Coordinators, which are defined as all Eastern Interconnection Reliability Coordinators and any Reliability Coordinators in other	~~The initiating Reliability Coordinator did not communicate the proposed actions to one or more of the required Reliability Coordinators, which are defined as all Eastern Interconenction Reliability Coordinators and any Reliability Coordinators in other~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4			Interconnections responsible for curtailing or reloading Interchange Transactions crossing Interconnection boundaries identified in the list of actions. (R3.2) OR The initiating Reliability Coordinator requested some, but not all, of the Reliability Coordinators identified in R3.3 to implement the identified ~~proposed~~ actions.	~~Interconnections responsible for curtailing or reloading Interchange Transactions crossing Interconnection boundaries identified in the proposed actions.~~ ~~OR~~ The initiating Reliability Coordinator ~~did not request~~requested n~~that~~ one ~~or more~~ of the Reliability Coordinators identified in R3.3 to implement the identified ~~proposed~~ actions. The responding Reliability Coordinator did not take one or more of the following actions: 1.) Implemented the requested actions. 2.) Implemented an alternative procedure that had been pre-approved by the ERO in lieu of some or all of the actions requested with equal or greater effect than the requested actions not being implemented. 3.) Implemented alternate actions ~~, provided that~~ based on analysis which showed that some or all of the actions in 1 or

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				2 would have resulted in a reliability concern or would have been ineffective, and that the alternate actions would not adversely affect reliability and were agreed to by the initiating Reliability Coordinator~~, and analysis showed that the alternate actions would not adversely affect reliability~~.
R5	The responding Reliability Coordinator communicated its actions taken to the initiating Reliability Coordinator, but did so more than ~~thirty~~ten minutes but not more than fifteen minutes after receiving the request. ~~(but not more than forty minutes after receiving the request).~~	The responding Reliability Coordinator communicated its actions taken to the initiating Reliability Coordinator, but did so more than fifteen ~~forty~~ minutes but not more than twenty minutes after receiving the request. ~~(but not more than fifty minutes after receiving the request).~~	The responding Reliability Coordinator communicated its actions taken to the initiating Reliability Coordinator, but did so more than ~~fifty~~twenty minutes but not more than twenty five minutes after receiving the request. ~~(but not more than one hour after receiving the request).~~	The responding Reliability Coordinator communicated its actions to the initiating Reliability Coordinator, but did so more than twenty five ~~one hour~~ minutes after receiving the request. OR The responding Reliability Coordinator did not communicate its actions to the initiating Reliability Coordinator. ~~OR~~ ~~The responding Reliability Coordinator communicated its actions to the initiating Reliability Coordinator in time, but the actions communicated did not match those implementedfailed to acknowledge all of the actions requested.~~

E. Regional Differences

None.

F. Associated Documents

G. Revision History

Version	Date	Action	Tracking
1		Creation of new standard, incorporating concepts from IRO-006-4 Attachment; elimination of Regional Differences, as the standard allows the use of Market Flow	New

Appendix A

The following criteria are intended to assist the Reliability Coordinator in determining what level of TLR to call. However, the Reliability Coordinator has the discretion to choose any of these levels regardless of the criteria listed below, provided the Reliability Coordinator has reliability reasons to take such action.

Level	System Condition
TLR-1	• At least one Transmission Facility is expected to approach or exceed its SOL or IROL within 8 hours.
TLR-2	• At least one Transmission Facility is approaching or is at its SOL or IROL. o Analysis shows that holding new and increasing non-firm transactions and energy flows for the next hour can prevent exceeding this SOL or IROL.
TLR-3a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. o Analysis shows that full or partial curtailment or reallocation[1] of non-firm transactions and energy flows can prevent exceeding this SOL and IROL.
TLR-3b	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. o Analysis shows that full or partial curtailment or reallocation[2] of non-firm transactions and energy flows can prevent exceeding this SOL or IROLs.
TLR-4	• At least one Transmission Facility is expected to exceed its SOL or IROL. • Analysis shows that full curtailment of non-firm transactions and energy flows, or reconfiguration of the transmission system can prevent exceeding this SOL or IROL.
TLR-5a	• At least one Transmission Facility is expected to exceed its SOL or IROL when the next-hour's transactions start. • Analysis shows that either of the following sets of actions can prevent exceeding the SOL or IROL: o Full curtailment non-firm transactions and energy flows, or o Reconfiguration of the transmission system, and full or partial curtailment or reallocation[3] of firm transactions and energy flows.

[1] "Reallocation" is a term defined within the NAESB TLR standards.

[2] "Reallocation" is a term defined within the NAESB TLR standards.

[3] "Reallocation" is a term defined within the NAESB TLR standards.

TLR-5b	• At least one Transmission Facility is exceeding its SOL or IROL, or
	• At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour.
	• Analysis shows that either of the following sets of actions can prevent exceeding the SOL or IROL:
	  o Full curtailment of non-firm transactions and energy flows, or
	  o Reconfiguration of the transmission system, and full or partial curtailment or reallocation of firm transactions and energy flows.

TLR-0	• No transmission facilities are expected to approach or exceed their SOL or IROL within 8 hours, and the ICM procedure may be terminated

E. Regional ~~Differences~~Variances

None.

F. Associated Documents

G. 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
4	October 23, 2007	Completed NERC/NAESB split	Revision
5		Removed Attachment 1 and made into a new standard, eliminated unnecessary requirements.	Revision

Implementation Plan for Standard IRO-006-5 (Reliability Coordination — Transmission Loading Relief (TLR)) and IRO-006-EAST-1 (Loading Relief Procedure for the Eastern Interconnection)

Summary

The NERC TLR Drafting Team has developed IRO-006-5 and IRO-006-~~EI~~EAST-1 as iterative and incremental improvements to IRO-006-4. This is one of three phases of Project 2006-08. The first phase, the split of the IRO-006-3 and its associated Attachment 1 into NERC and NAESB standards, was completed and approved by the NERC Board of Trustees on October 23, 2007, and filed with regulatory authorities on December 21, 2008. The second phase, which is intended to address any needed modifications to the standards based on the PJM/~~MISP~~MISO/SPP waivers, is currently undergoing Field Testing. This implementation plan addressed the third phase, which is intended to improve the quality of the standards.

The Drafting Team has made significant revisions to the previous IRO-006-4 and Attachment 1:

1. Converted Attachment 1 into a standard solely for the Eastern Interconnection.
2. Transferred requirements from IRO-006-4 that were primarily focused on Eastern Interconnection practices to the Eastern Interconnection TLR standard.
3. Clarified the roles of entities when responding to curtailment requests from other Interconnections.
4. Removed the requirement that entities comply with the INT standards, as it was redundant.
5. Restructured the Eastern Interconnection TLR standard (previously Attachment 1) to be clearer and specify reliability requirements.
6. Removed the requirement in IRO-006-5 that specified the appropriate methods to utilize within each Interconnection, instead relying on regional standards for the three Interconnections to capture this information.
7. Expanded the applicability of IRO-006-5 to include the Transmission Operator and the Balancing Authority.

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

Modified Standards

IRO-006-4, and associated Attachment 1, should be retired when IRO-006-5 and IRO-~~006-EI~~006-EAST-1 become effective.

The definition of "Reallocation" should be removed from the Glossary when IRO-006-5 and IRO-~~006-EI~~006-EAST-1 become effective.

The Regional Differences within IRO-006-4 should be retired when IRO-006-5 and IRO-~~006-EI~~006-EAST-1 become effective.

Compliance with Standards

Once the standards become effective, the responsible entities identified in the applicability section of the standards must comply with the requirements. These ~~include~~include the following:

- ~~Reliability Coordinators~~

Proposed Standard	Transmission Operator	Balancing Authority	Reliability Coordinator
IRO-006-5	■	■	■
IRO-006-EAST-1			■

Proposed Effective Date

The standards will become effective on the first day of the first calendar quarter ~~that~~ after the date the standards are both approved by applicable regulatory authorities~~,~~ ; or in those jurisdictions where regulatory approval is not required, the standards becomes effective on the first day of the first calendar quarter after the date the standards are both approved by the NERC Board of Trustees.

Consideration of Comments on Second Draft of IRO-006-5 — Reliability Coordination — Transmission Loading Relief and IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection (Project 2006-08)

The Transmission Loading Relief Standard Drafting Team (TLR SDT) thanks all commenters who submitted comments on the second draft of IRO-006-5 — Reliability Coordination — Transmission Loading Relief and IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection. These standards were posted for a 45-day public comment period from February 19, 2009 through April 6, 2009. Stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 17 sets of comments, including comments from 60 different people from 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Most comments received on the standards were favorable. Some entities questioned whether NERC was allowed to create an Interconnection-wide standard; the SDT believes that NERC is able to take this approach.

The majority of respondents supported the changes to the applicability of IRO-006-5, but some entities suggested that including the Transmission Operator as a responding entity did not make sense. The SDT concurred and removed the Transmission Operator as an applicable entity. Some entities suggested that the Interchange Authority should be included; the team disagreed, believing that any role for the Interchange Authority should be addressed in the INT standards.

Several entities questioned whether reloading should be included in the standard. The team removed the concept of mandatory reloading, as this is not the way reloading works in reality.

Several entities expressed concern with the VSLs for the standards. The SDT has attempted to clarify the VSLs in the latest draft. All comments received can be reviewed at the following site:

http://www.nerc.com/filez/standards/Reliability-Coordination-Transmission-Loading-Relief.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Jason Marshall	Midwest ISO Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Cyrulewski	JDRJC Associates	RFC	8

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Michael Brytowski	MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carol Gerou	MP	MRO	1, 3, 5, 6
2.	Neal Balu	WPS	MRO	3, 4, 5, 6
3.	Terry Bilke	MISO	MRO	2
4.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
5.	Ken Goldsmith	ALTW	MRO	4
6.	Jim Haigh	WAPA	MRO	1, 6
7.	Terry Harbour	MEC	MRO	1, 3, 5, 6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	8.	Joseph Knight	GRE	MRO					1, 3, 5, 6				
	9.	Scott Nickels	RPU	MRO					3, 4, 5, 6				
	10.	Dave Rudolph	BEPC	MRO					3, 5, 6, 1				
	11.	Eric Ruskamp	LES	MRO					1, 3, 5, 6				
	12.	Pam Sordet	XCEL	MRO					1, 3, 5, 6				
3.	Group	Michael Gammon	Kansas City Power & Light (KCPL)	X		X		X	X				
		Additional Member	**Additional Organization**	**Region**					**Segment Selection**				
	1.	Jim Useldinger	Kansas City Power & Light	SPP					1, 3, 5, 6				
	2.	Denney Fales	Kansas City Power & Light	SPP					1, 3, 5, 6				
	3.	Tom Saitta	Kansas City Power & Light	SPP					1, 3, 5, 6				
4.	Group	Marc Butts	Southern Company Transmission	X									
		Additional Member	**Additional Organization**	**Region**					**Segment Selection**				
	1.	Hugh Francis	Southern Company Services, Inc.	SERC					1				
	2.	J. T. Wood	Southern Company Services, Inc.	SERC					1				
	3.	Chris Wilson	Southern Company Services, Inc.	SERC					1				
5.	Group	Denise Koehn	Bonneville Power Administration (BPA)	X		X		X	X				
		Additional Member	**Additional Organization**	**Region**	**Segment Selection**								
	1.	Thomas Westbrook	Tx Pre-Schedule & Real Time Scheduling	WECC	1								
	2.	Angie Lumbert	Tx Operational Analysis & Support	WECC	1								
	3.	Wes Hutchison	Tx Operational Analysis & Support	WECC	1								
6.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				
		Additional Member	**Additional Organization**	**Region**					**Segment Selection**				
	1.	Dave Folk	FE	RFC					1, 3, 4, 5, 6				
	2.	Doug Hohlbaugh	FE	RFC					1, 3, 4, 5, 6				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Group	Guy Zito	Northeast Power Coordinating Council (NPCC)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Al Adamson	New York State Reliability Council	NPCC	10
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Manuel Couto	National Grid	NPCC	1
8.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
10.	Brian Evans-Mongeon	Utility Services	NPCC	6
11.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
12.	Mike Gildea	Constellation Energy	NPCC	6
13.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
14.	Kathleen Goodman	ISO - New England	NPCC	2
15.	David Kiguel	Hydro One Networks Inc.	NPCC	1
16.	Randy MacDonald	New Brunswick System Operator	NPCC	2
17.	Bruce Metruck		NPCC	6
18.	Don Nelson		NPCC	9
19.	Chris Orzel		NPCC	5
20.	Lee Pedowicz		NPCC	10
21.	Robert Pellegrini		NPCC	1
22.	Michael Schiavone		NPCC	1
23.	Rick White		NPCC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	24. Peter Yost						NPCC					3	
8.	Individual	Jason Shaver	American Transmission Company (ATC)	X									
9.	Individual	Dan Rochester	Independent Electricity System Operator (IESO)		X								
10.	Individual	Greg Rowland	Duke Energy Corporation	X		X		X	X				
11.	Individual	Howard Rulf	We Energies			X	X	X					
12.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
13.	Individual	Jack Cashin/Barry Green	Electric Power Supply Association (EPSA)					X	X				
14.	Individual	Patrick Brown	PJM Interconnection		X								
15.	Individual	Jeff Hackman	Ameren	X									
16.	Individual	Edward Davis	Entergy Services, Inc.	X		X		X	X				
17.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
18.		Ben Li	ISO/RTO Council										

1. **The drafting team has removed the requirement from IRO-006-5 that indicated which methods were used in each of the Interconnections, instead relying on regional standards (with IRO-006-EAST-1 serving as an Interconnection-wide standard) for the three Interconnections to capture this information. Do you believe this to be appropriate?**

Summary Consideration: The majority of comments agreed that this was appropriate. Those who objected questioned whether NERC was allowed to create an Interconnection-wide standard. The SDT believes that NERC is able to take this approach. Regarding whether or not WECC and ERCOT were being held to the same standard as the Eastern Interconnection, the team believes this is not an area of valid concern – and if it was, due to the technical deference afforded to WECC and ERCOT, the ERO would likely not be the proper forum to address it.

Organization	Yes or No	Question 1 Comment
Midwest ISO Standards Collaborators	Yes	While we generally agree with this approach, it is actually somewhat confusing. IRO-006-EAST-1 is not a regional standard but a inter-connection wide standard and is thus posted with the IRO-006-5. This causes one to question why the other regional standards aren't posted but that is because they are truly regional standards and handled by WECC and ERCOT since their Interconnections are the same as the region. We question if an interconnection wide standard for the Eastern Interconnection is in fact supported by the NERC Rules of Procedure. Given the decoupling of the ERCOT and WECC region standards from this Interconnection wide standard effort, we fear that the Eastern Interconnection could be held to a higher standard than the WECC and ERCOT. What precautions is the drafting team taking to prevent this from happening?
Response: The EPAct requires that NERC give a “rebuttable presumption” of technical validity to the WECC and ERCOT approaches. Accordingly, the venue to address concerns with the WECC or ERCOT approaches is not within the Continent-wide NERC community – it is either within the WECC or ERCOT processes, or at the FERC. NERC’s Rules of Procedure do not prohibit the creation of Interconnection-wide standards. In previous postings, the drafting team questioned whether there was a preference for a continent-wide standard with interconnection-wide applicability or if there should be an interconnection-wide standard. Slightly more than 50% indicated they preferred the interconnection-wide standard, while approximately		

Organization	Yes or No	Question 1 Comment
30% preferred the continent-wide standard with interconnection-wide applicability. Additionally, as both WECC and ERCOT are single RC areas, they do not necessarily need the kind of RC to RC coordination described in IRO-006-EAST. The Eastern Interconnection, with its multiple RCs, does have a need for coordination between RCs. Accordingly, the standard has requirements for RC to RC coordination that are not needed in WECC or ERCOT, which may indeed be a higher standard – but not one that would be applicable in those areas.		
MRO NERC Standards Review Subcommittee	No	While we generally agree with this approach, it is actually somewhat confusing. IRO-006-EAST-1 is not a regional standard but a inter-connection wide standard and is thus posted with the IRO-006-5. This causes one to question why the other regional standards aren't posted but that is because they are truly regional standards and handled by WECC and ERCOT since their Interconnections are the same as the region. We question if an interconnection wide standard for the Eastern Interconnection is in fact supported by the NERC Rules of Procedure. Given the decoupling of the ERCOT and WECC region standards from this Interconnection wide standard effort, we fear that the Eastern Interconnection could be held to a higher standard than the WECC and ERCOT. What precautions is the drafting team taking to prevent this from happening?
Response: The EPAct requires that NERC give a "rebuttable presumption" of technical validity to the WECC and ERCOT approaches. Accordingly, the venue to address concerns with the WECC or ERCOT approaches is not within the Continent-wide NERC community – it is either within the WECC or ERCOT processes, or at the FERC. NERC's Rules of Procedure do not prohibit the creation of Interconnection-wide standards. In previous postings, the drafting team questioned whether there was a preference for a continent-wide standard with interconnection-wide applicability or if there should be an interconnection-wide standard. Slightly more than 50% indicated they preferred the interconnection-wide standard, while approximately 30% preferred the continent-wide standard with interconnection-wide applicability. Additionally, as both WECC and ERCOT are single RC areas, they do not necessarily need the kind of RC to RC coordination described in IRO-006-EAST. The Eastern Interconnection, with its multiple RCs, does have a need for coordination between RCs. Accordingly, the standard has requirements for RC to RC coordination that are not needed in WECC or ERCOT, which may indeed be a higher standard –		

Organization	Yes or No	Question 1 Comment
but not one that would be applicable in those areas.		
ISO/RTO Council	Yes and No	While we generally agree with this approach, it is actually somewhat confusing. IRO-006-EAST-1 is not a regional standard but a inter-connection wide standard and is thus posted with the IRO-006-5. This causes one to question why the other regional standards aren't posted but that is because they are truly regional standards and handled by WECC and ERCOT since their Interconnections are the same as the region. We question if an interconnection wide standard for the Eastern Interconnection is in fact supported by the NERC Rules of Procedure.
Response: The EPAct requires that NERC give a “rebuttable presumption” of technical validity to the WECC and ERCOT approaches. Accordingly, the venue to address concerns with the WECC or ERCOT approaches is not within the Continent-wide NERC community – it is either within the WECC or ERCOT processes, or at the FERC. NERC’s Rules of Procedure do not prohibit the creation of Interconnection-wide standards. In previous postings, the drafting team questioned whether there was a preference for a continent-wide standard with interconnection-wide applicability or if there should be an interconnection-wide standard. Slightly more than 50% indicated they preferred the interconnection-wide standard, while approximately 30% preferred the continent-wide standard with interconnection-wide applicability.		
FirstEnergy	Yes	We agree. We would also suggest requirement R1 of IRO-006-5 be revised to be a "directive" rather than a "request". If an entity must comply with the request then it should come in the form of an RC directive; even if it is a directive from one RC to another RC.
Response: The SDT believes this is not a true “directive” – it is simply RC to RC coordination.		
KCPL	Yes	
Southern Company Transmission	Yes	N/A
BPA	Yes	

Organization	Yes or No	Question 1 Comment
NPCC	Yes	
American Transmission Company	Yes	
IESO	Yes	
Duke Energy Corporation	Yes	
We Energies	Yes	
American Electric Power	Yes	
EPSA	Yes	
PJM Interconnection	Yes	
Ameren	Yes	
PacifiCorp	Yes	

2. The drafting team has expanded the applicability of IRO-006-5 to include the Transmission Operator and the Balancing Authority. Do you believe this to be appropriate?

Summary Consideration: The majority of comments supported the addition. However, some entities suggested that including the Transmission Operator as a responding entity did not make sense. The SDT concurred and removed the Transmission Operator as an applicable entity.

Some entities suggested that the Interchange Authority should be included; the team disagreed, believing that any role for the Interchange Authority should be addressed in the INT standards.

Some entities suggested there was a potential for conflict between entities in different Interconnections. The SDT does not agree that the potential for conflict exists.

Organization	Yes or No	Question 2 Comment
Midwest ISO Standards Collaborators	No	We agree with the drafting team inclusion of the BA. It is not clear to us why the Transmission Operator is included. What role does the Transmission Operator play in curtailing an Interchange Transaction. This may be confusing the TOP with TSP or IA.
Response: The drafting team agrees, and has removed the Transmission Operator from the applicability of the standard. Note that Transmission Operators are still referenced in R1 as entities that may send requests to Reliability Coordinators and Balancing Authorities.		
MRO NERC Standards Review Subcommittee	No	We agree with the drafting team inclusion of the BA. It is not clear to us why the Transmission Operator is included. What role does the Transmission Operator play in curtailing an Interchange Transaction. This may be confusing the TOP with TSP or IA.
Response: The drafting team agrees, and has removed the Transmission Operator from the applicability of the standard. Note that Transmission Operators are still referenced in R1 as entities that may send requests to Reliability Coordinators and Balancing Authorities.		
American Transmission Company	No	We agree with the inclusion of the BA but do not agree with the inclusion of the TOP. ATC does not believe that the TOP plays a role in this standard and that maybe the team is confusing the TOP with the TSP or IA.

Organization	Yes or No	Question 2 Comment
		What responsibility does the Transmission Operator have in curtailing an Interchange Transaction?
Response: The drafting team agrees, and has removed the Transmission Operator from the applicability of the standard. Note that Transmission Operators are still referenced in R1 as entities that may send requests to Reliability Coordinators and Balancing Authorities.		
ISO/RTO Council	No	We agree with the drafting team inclusion of the BA. It is not clear to us why the Transmission Operator is included. What role does the Transmission Operator play in curtailing an Interchange Transaction. This may be confusing the TOP with TSP or IA.
Response: The drafting team agrees, and has removed the Transmission Operator from the applicability of the standard. Note that Transmission Operators are still referenced in R1 as entities that may send requests to Reliability Coordinators and Balancing Authorities.		
FirstEnergy	No	We understand per the SDT response to comments ("IRO-006-5 R2 has been modified to include Transmission Operators and Balancing Authorities, which the SDT believes will further support the WECC practices") that the TOP and BA were added to the applicability to reflect WECC practices. Although we believe a continent-wide standard should capture all best practices, it should not cause issues with any other region or interconnection. In the East interconnection entities are ultimately bound by the RC directives since they have the highest level of authority. The requirement takes WECC into account but could cause compliance issues to a TOP or BA in the Eastern interconnection if it did not follow through on a request from a neighboring TOP or BA because they were already bound by a request from an RC. The phrase "as appropriate for the neighboring Interconnection" is also ambiguous and could add to conflict and varying interpretations. The wording needs clarity and we suggest that the TOP/BA applicability only be included in WECC's TLR standard IRO-006-WECC-1 if it is only appropriate in the Western Interconnection.Also, this applicability may conflict with IRO-001-1 which requires "R1. Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries." Therefore all segments of any interconnection have a Reliability Coordinator to coordinate emergency operations and issue directives to the BAs and TOPs.
Response: The ambiguous language has been removed. However, we believe there should not be any conflict, as the requirement includes a provision to not implement the request if the applicable entity "provides a reliability reason that it cannot comply with the request." This reason could include a statement that the local RC was forbidding the requested action. Note the requirement only applies to requests to curtail Interchange transactions that cross an Interconnection Boundary, and the request must be made as part of an Interconnection-wide congestion management		

Organization	Yes or No	Question 2 Comment
procedure. Given these limitations, we do not believe there to be a potential for conflict.		
Southern Company Transmission	Yes	The Drafting Team might also consider including Interchange Authorites. Please see our comments at Question #7.
Response: The drafting team believes that the Interchange Authority function provides coordination of interchange transaction changes (which may occur as a result of this standard), but it is not directly involved. To the extent requirements are needed to define tasks for the Interchange Authority related to Interchange, they will most likely be addressed in the INT standards.		
KCPL	Yes	
BPA	Yes	
NPCC	Yes	
IESO	Yes	
Duke Energy Corporation	Yes	
We Energies	Yes	
American Electric Power	Yes	
EPSA	Yes	
PJM Interconnection	Yes	
Ameren	Yes	
PacifiCorp	Yes	

3. **The drafting team has included measures and data retention period for IRO-006-5. Do you agree with these measures and the data retention period?**

Summary Consideration: The majority of comments supported the language.

Several entities questioned whether reloading should be included in the standard. The team removed the concept of mandatory reloading, as this is not the way reloading works in reality. The team also explained R1 in more detail, and removed some ambiguous language in the requirement.

Organization	Yes or No	Question 3 Comment
Southern Company Transmission	No	There is no need to require compliance with reload requests when the reloads are due to the the level of the TLR being reduced (ie. level 3 to level 1). The reload is due to the fact that the flowgate can take more flow than is currently allowed. Reloads are a commercial issue and not a reliability issue. They also conflict with current business practices such as off hour ramping for non-reliability reasons.Reloading is referenced in IRO-006-5 at:Requirement R1Measure M1VSL for R1and in IRO-006-EAST-1 at:Requirement R3.2.2Requirement R3.3.1Requirement R3.3.2Requirement R3.3.3Requirement R3.3.4Measure M3 (2)VSL for R3It is our opinion that reloading, and the references to it, should be removed from the two standards.
Response: The drafting team concurs, and has removed “reloading” from the proposed IRO-006-5 and IRO-006-EAST-1.		
FirstEnergy	No	Per our previous comments regarding the TOP/BA applicability, including them in this standard and along with measures could cause a double jeopardy violation for the same infraction.
Response: As discussed in response to the previous comment, the SDT does not believe that there is any potential for double jeopardy.		
NPCC	No	Please explain the intent of the words "as appropriate" in R1. This suggests that Balancing Authorities (BAs) and Transmission Operators (TOPs) (in addition to Reliability Coordinators) in another Interconnection, are also authorized to make requests to curtail or reload a transaction pursuant to an Interconnection-wide transmission loading relief procedure. Are they authorized "by default", or is it expected that BAs and TOPs

Organization	Yes or No	Question 3 Comment
		will receive their authorization based on an agreement between the neighboring Reliability Coordinators? In brief, what is the expected protocol for making these requests and how is it to be set up?
Response: The ambiguous "as appropriate" language has been removed. However, in general, it is possible that Transmission Operators and Balancing Authorities may initiate curtailment of Interchange Transactions based on interconnection-wide congestion management activities. The intent of this requirement is to make it clear that should such requests be received in a different Interconnection than that from which the request originated, the BA or RC is required to either honor the request or explain why they cannot honor the request.		
IESO	No	Please explain the intent of the words "as appropriate" in R1. This suggests that Balancing Authorities (BAs) and Transmission Operators (TOPs) (in addition to Reliability Coordinators) in another Interconnection, are also authorized to make requests to curtail or reload a transaction pursuant to an Interconnection-wide transmission loading relief procedure. Are they authorized "by default", or is it expected that BAs and TOPs will receive their authorization based on an agreement between the neighbouring Reliability Coordinators? In brief, what is the expected protocol for making these requests and how is it to be set up?
Response: The ambiguous "as appropriate" language has been removed. However, in general, it is possible that Transmission Operators and Balancing Authorities may initiate curtailment of Interchange Transactions based on interconnection-wide congestion management activities. The intent of this requirement is to make it clear that should such requests be received in a different Interconnection than that from which the request originated, the BA or RC is required to either honor the request or explain why they cannot honor the request.		
We Energies	No	R1 states that the requesting RC, BA, or TOP are in another interconnection. M1 needs to also state that. Also "reload" needs to be removed (see question #7).
Response: The SDT has modified the standard to remove "reload," and modified M1 to include the reference to "another interconnection" as suggested.		
Midwest ISO Standards Collaborators	Yes	
MRO NERC Standards Review Subcommittee	Yes	

Organization	Yes or No	Question 3 Comment
KCPL	Yes	
BPA	Yes	
American Transmission Company	Yes	
Duke Energy Corporation	Yes	
American Electric Power	Yes	
PJM Interconnection	Yes	
Ameren	Yes	
PacifiCorp	Yes	
ISO/RTO Council	Yes	

4. The drafting team has included measures and data retention period for IRO-006-EAST-1. Do you agree with these measures and the data retention period?

Summary Consideration: The majority of comments supported the measures and data retention. The team made minor edits based on suggestions received.

Organization	Yes or No	Question 4 Comment
Duke Energy Corporation	No	Measure M1 and the associated Requirement R1 and VSL all include the descriptive phrase "more effective" when describing actions other than a TLR to be taken to mitigate an IROL exceedance. This phrase introduces uncertainty and unnecessary compliance risk and should be deleted since the actions to be taken are spelled out in the Requirement (i.e. reconfiguration, redispatch, use of DSM and load shedding). Compliance should not depend upon an after-the-fact determination of how effective the actions turned out to be. Additionally, the way Requirement R1 is written, it could be interpreted to mean that all of the listed actions must be taken, as a minimum. R1 should state that actions to be taken "could include", but are not limited to reconfiguration, etc.
Response: The drafting team has modified the language or R1 and M1 to address your concerns.		
PJM Interconnection	No	The combination of requirments in this standard make sense, particularly as they pertain to IROLs and the need to plan, implement and communicate all steps needed to mitigate the IROL exceedance as quickly as possible.The issue is that the wording in requirements 1 through 4 may setup either an explicit (intended by the SDT) or implicit (not intended, but open to interpretation by auditors) logging and reporting requirement to log all actions "to be taken", i.e., the plan for each and every SOL (IROLs may make sense) as wells as each and every hour until the TLR is set as a TLR 0. Non-compliance could be as benign as failing to log all of the action steps "to be taken" for a particular hour of a TLR level 1 for any SOL that has been in effect during the entire peak period. The excessive reporting/data retention requirements will not provide commensurate improvement in system reliability.R2. When initiating the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance, and at least every clock hour after initiation, up to and including the hour when the TLR level has been identified as TLR Level 0, the Reliability Coordinator shall identify: R2.1. The TLR level in accordance with the criteria in Appendix A, and R2.2. A list of actions to take, based on the

Organization	Yes or No	Question 4 Comment
		TLR level chosen.PJM suggests that the wording be changed to reflect that all actions taken be logged, but remove any implicit or explicit reference to the requirement to log all actions "to be taken", i.e., the plan for each and every SOL (IROLs may make sense) as wells as each and every hour until the TLR is set as a TLR 0.
Response: The drafting team has modified the standard to use the phrase "congestion management actions to be implemented"		
Southern Company Transmission	No	Please see response to Question #3.
Response: Please see question 3 for response.		
American Transmission Company	No	Please see our comment to question 2
Response: Please see question 2 for response.		
NPCC	Yes	1. While we generally agree with the measures and data retention period, we do have a concern with the phrase "prior to or in conjunction with" in R1. We interpret the intent here to be that the Reliability Coordinator would, in response to an IROL exceedance, initiate local control procedures first, followed by the TLR procedure, or at least the two procedures would be carried out at the same time. The phrase in question leaves open the possibility that the TLR procedure may be initiated first with other control actions coming later, an ambiguity we believe should be cleared up at this stage if this is not the intent. We therefore suggest the following alternative phrasing "either prior to or simultaneously with". M1 would therefore have to be changed. 2. In M3, there is a typo in line 2. The word "for" should be removed.
Response: The drafting team has modified R1, M1, and M3 as suggested.		
IESO	Yes	1. While we generally agree with the measures and data retention period, we do have a concern with the phrase "prior to or in conjunction with" in R1. We interpret the intent here to be that the Reliability Coordinator would, in response to an IROL exceedance, initiate local control procedures first, followed by the TLR procedure, or at least the two procedures would be carried out at the same time. The phrase in question leaves open the possibility that the TLR procedure may be initiated first with other control actions coming

Organization	Yes or No	Question 4 Comment
		later, an ambiguity we believe should be cleared up at this stage if this is not the intent. We therefore suggest the following alternative phrasing "either prior to or simultaneously with". M1 would therefore have to be changed. 2. In M3, there is a typo in line 2. The word "for" should be removed.
Response: The drafting team has modified R1, M1, and M3 as suggested.		
Midwest ISO Standards Collaborators	Yes	
MRO NERC Standards Review Subcommittee	Yes	
KCPL	Yes	
FirstEnergy	Yes	
We Energies	Yes	
American Electric Power	Yes	
EPSA	Yes	
Ameren	Yes	
ISO/RTO Council	Yes	
PacifiCorp		None

5. The drafting team has included Violation Severity Levels for IRO-006-5. Do you agree with these Violation Severity Levels?

Summary Consideration: Slightly more than half of the comments supported the IRO-006-5 VSLs. The team removed references to reloading from the standards, as discussed previously. Some entities objected to the use of a "binary" VSL; the team explained the use of VSLs and its rationale for selecting this particular approach.

Organization	Yes or No	Question 5 Comment
Midwest ISO Standards Collaborators	No	The Commission established in their June 19, 2008 order conditional approving VSLs that they prefer VSLs to have as many levels as possible defined in paragraph 27. For IRO-006-5 R1, we believe that it is possible and preferable to assign two VSLs rather than one by splitting the response to reloads from the response for curtailments. When you further consider that reloading is not a reliability issue but an equity issue (that is a market participant wants their transaction to flow for as long as possible to increase their revenue and the Transmission Provider does as likewise to avoid crediting the Transmission Reservation usage charges for the curtailments), the Lower VSL level should be used for it. Thus, we propose the following VSLs for IRO-006-5 R1:Lower: The applicable entity received a request to reload an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority or Transmission Operator, but the entity neither complied with the request nor provided a reliability reason it could not comply with the request. Severe: The applicable entity received a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority or Transmission Operator, but the entity neither complied with the request nor provided a reliability reason it could not comply with the request.
Response: The drafting team has eliminated reloading from the standard.		
MRO NERC Standards Review Subcommittee	No	The Commission established in their June 19, 2008 order conditional approving VSLs that they prefer VSLs to have as many levels as possible defined in paragraph 27. For IRO-006-5 R1, we believe that it is possible and preferable to assign two VSLs rather than one by splitting the response to reloads from the response for curtailments. When you further consider that reloading is not a reliability issue but an equity issue (that is a

Organization	Yes or No	Question 5 Comment
		market participant wants their transaction to flow for as long as possible to increase their revenue and the Transmission Provider does as likewise to avoid crediting the Transmission Reservation usage charges for the curtailments), the Lower VSL level should be used for it. Thus, we propose the following VSLs for IRO-006-5 R1:Lower: The applicable entity received a request to reload an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority or Transmission Operator, but the entity neither complied with the request nor provided a reliability reason it could not comply with the request.Severe: The applicable entity received a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority or Transmission Operator, but the entity neither complied with the request nor provided a reliability reason it could not comply with the request.
Response: The drafting team has eliminated reloading from the standard.		
ISO/RTO Council	No	The Commission established in their June 19, 2008 order conditional approving VSLs that they prefer VSLs to have as many levels as possible defined in paragraph 27. For IRO-006-5 R1, we believe that it is possible and preferable to assign two VSLs rather than one by splitting the response to reloads from the response for curtailments. When you further consider that reloading is not a reliability issue but an equity issue (that is a market participant wants their transaction to flow for as long as possible to increase their revenue and the Transmission Provider does as likewise to avoid crediting the Transmission Reservation usage charges for the curtailments), the Lower VSL level should be used for it. Thus, we propose the following VSLs for IRO-006-5 R1: Lower: The applicable entity received a request to reload an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority or Transmission Operator, but the entity neither complied with the request nor provided a reliability reason it could not comply with the request. Severe: The applicable entity received a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority or Transmission Operator, but the entity neither complied with the request nor provided a reliability reason it could not comply with the request.

Organization	Yes or No	Question 5 Comment
Response: The drafting team has eliminated reloading from the standard.		
Southern Company Transmission	No	We again take exception to reloads being included in the standard. Is there an instance/example of when a reload that was not performed caused a reliability problem on a flowgate currently under TLR?
Response: The drafting team has eliminated reloading from the standard.		
FirstEnergy	No	If the communiction is truly a request that is not honored, then the VSL should be a lower not a severe. If it is a directive that is not followed as we have suggested in the response to question 1 then a severe is appropriate.
Response: VSLs do not describe the risk of a violation, but the extent to which a violation occurred. In this case, either the request was honored (or not honored but explained), or it was not. As such, there is only 0% compliance or 100% compliance. In the case of 0% compliance, the SDT is treating this as a complete failure to meet the requirement; hence, the use of the Severe VSL. Note that this is not a directive - it is intended to be communication of a desired outcome, followed by either concurrence or negotiation of a compromise outcome.		
American Transmission Company	No	he standard requires a response to a request, not a directive. This distinction implies that the request is less onerous than a directive and should, therefore, have a lower severity level. In addition, the reload of an Interchange Transaction is not a reliability issue but a market issue and should have a lower severity level.
Response: VSLs do not describe the risk of a violation, but the extent to which a violation occurred. In this case, either the request was honored (or not honored but explained), or it was not. As such, there is only 0% compliance or 100% compliance. In the case of 0% compliance, the SDT is treating this as a complete failure to meet the requirement; hence, the use of the Severe VSL. Note that this is not a directive - it is intended to be communication of a desired outcome, followed by either concurrence or negotiation of a compromise outcome. The drafting team has eliminated reloading from the standard.		
We Energies	No	Same comment as #3, remove reload. Requesting RC, BA, or TOP is in another interconnection.
Response: The drafting team has eliminated reloading from the standard.		

Organization	Yes or No	Question 5 Comment
The standard has been clarified to indicate that the requestor must be from another Interconnection.		
BPA	Yes	
KCPL	Yes	
NPCC	Yes	
IESO	Yes	
Duke Energy Corporation	Yes	
American Electric Power	Yes	
PJM Interconnection	Yes	
Ameren	Yes	
PacifiCorp	Yes	

6. The drafting team has included Violation Severity Levels for IRO-006-EAST-1. Do you agree with these Violation Severity Levels?

Summary Consideration: Only a small number of comments supported the VSLs for IRO-006-EAST-1. Some entities had concerns with the use of the phrase "some, but not all." The SDT explained the use of this term. Some entities suggested the need for consistency between the requirements and the VSLs; the drafting team made changes to address this shortcoming. One entity suggested removing the concept of timeliness from R5; the team disagreed with the suggestion.

Organization	Yes or No	Question 6 Comment
Midwest ISO Standards Collaborators	No	Please split the tables into rows. It is difficult to detect where the VSLs for one requirement end and another requirement begin.We believe part of the High VSL is ambiguous thus violates the Commission's guideline 2 (specifically part b) established in their June 19, 2008 order on VSLs. Specifically, how many is some? Use of the term some will result in inconsistent enforcement. Additionally, we note that it is not clear what VSL applies when all of the sub-requirements 3.1-3.3 are violated. To ensure various combinations of the violations of the sub-requirments are covered in all the VSLs and to make the VSLs consistent with the direction the VSL drafting team is applying to VSLs, we suggest the following VSLs: Lower: The initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level. (R3.1) Moderate: The initiating Reliability Coordinator did not communicate the list of actions to one or more of the required Reliability Coordinators, which are defined as all Eastern Interconnection Reliability Coordinators and any Reliability Coordinators in other Interconnections responsible for curtailing or reloading Interchange Transactions crossing Interconnection boundaries identified in the list of actions. (R3.2) OR The initiating Reliability Coordinator did not request one or more of the Reliability Coordinators identified in R3.3 to implement the identified actions. High: The initiating Reliability Coordinator violated two of the sub-requirements R3.1, R3.2, and R3.3 as

Organization	Yes or No	Question 6 Comment
		described in the Lower or Moderate VSLs. Severe: The initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level. (R3.1) AND The initiating Reliability Coordinator did not communicate the list of actions to one or more of the required Reliability Coordinators, which are defined as all Eastern Interconnection Reliability Coordinators and any Reliability Coordinators in other Interconnections responsible for curtailing or reloading Interchange Transactions crossing Interconnection boundaries identified in the list of actions. (R3.2) AND The initiating Reliability Coordinator did not request one or more of the Reliability Coordinators identified in R3.3 to implement the identified actions.
Response: The table has been modified so the row delineations will display correctly. The drafting team believes the VSLs are clear as written. Note that the use of the phrase “some” would be ambiguous if other options were provided and intended to imply a relative scale (e.g., few, some, many, etc…). However, the definition of “some” is generally defined as being a part of a set of unspecified size. In this case, the VSL is graded based on ALL actions being taken, SOME actions being taken, or NO actions being taken. SOME, therefore, indicates that at least one action was taken (therefore the entity has met more than 0% of their obligation), but not all actions were taken (so the entity did not meet 100% of their obligation). We believe that this use, in this context, is appropriate.		
MRO NERC Standards Review Subcommittee	No	Please split the tables into rows. It is difficult to detect where the VSLs for one requirement end and another requirement begin.We believe part of the High VSL is ambiguous thus violates the Commission's guideline 2 (specifically part b) established in their June 19, 2008 order on VSLs. Specifically, how many is some? Use of the term some will result in inconsistent enforcement. Additionally, we note that it is not clear what VSL applies when all of the sub-requirements 3.1-3.3 are violated. To ensure various combinations of the violations of the sub-requirments are covered in all the VSLs and to make the VSLs consistent with the direction the VSL drafting team is applying to VSLs, we suggest the following VSLs: Lower: The initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level. (R3.1) Moderate: The initiating Reliability Coordinator did not communicate the list of actions to one or more of the

Organization	Yes or No	Question 6 Comment
		required Reliability Coordinators, which are defined as all Eastern Interconnection Reliability Coordinators and any Reliability Coordinators in other Interconnections responsible for curtailing or reloading Interchange Transactions crossing Interconnection boundaries identified in the list of actions. (R3.2) OR The initiating Reliability Coordinator did not request one or more of the Reliability Coordinators identified in R3.3 to implement the identified actions. High: The initiating Reliability Coordinator violated two of the sub-requirements R3.1, R3.2, and R3.3 as described in the Lower or Moderate VSLs. Severe: The initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level. (R3.1) ANDThe initiating Reliability Coordinator did not communicate the list of actions to one or more of the required Reliability Coordinators, which are defined as all Eastern Interconnection Reliability Coordinators and any Reliability Coordinators in other Interconnections responsible for curtailing or reloading Interchange Transactions crossing Interconnection boundaries identified in the list of actions. (R3.2) AND The initiating Reliability Coordinator did not request one or more of the Reliability Coordinators identified in R3.3 to implement the identified actions.
Response: The table has been modified so the row delineations will display correctly. The drafting team believes the VSLs are clear as written. Note that the use of the phrase "some" would be ambiguous if other options were provided and intended to imply a relative scale (e.g., few, some, many, etc…). However, the definition of "some" is generally defined as being a part of a set of unspecified size. In this case, the VSL is graded based on ALL actions being taken, SOME actions being taken, or NO actions being taken. SOME, therefore, indicates that at least one action was taken (therefore the entity has met more than 0% of their obligation), but not all actions were taken (so the entity did not meet 100% of their obligation). We believe that this use, in this context, is appropriate.		
ISO/RTO Council	No	Please split the tables into rows. It is difficult to detect where the VSLs for one requirement end and another requirement begin. We believe part of the High VSL is ambiguous thus violates the Commission's guideline 2 (specifically part b) established in their June 19, 2008 order on VSLs. Specifically, how many is some? Use of the term some will result in inconsistent enforcement. Additionally, we note that it is not clear what VSL applies when all of the sub-

Organization	Yes or No	Question 6 Comment
		requirements 3.1-3.3 are violated. To ensure various combinations of the violations of the sub-requirments are covered in all the VSLs and to make the VSLs consistent with the direction the VSL drafting team is applying to VSLs, we suggest the following VSLs: Lower: The initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level. (R3.1) Moderate: The initiating Reliability Coordinator did not communicate the list of actions to one or more of the required Reliability Coordinators, which are defined as all Eastern Interconnection Reliability Coordinators and any Reliability Coordinators in other Interconnections responsible for curtailing or reloading Interchange Transactions crossing Interconnection boundaries identified in the list of actions. (R3.2) OR The initiating Reliability Coordinator did not request one or more of the Reliability Coordinators identified in R3.3 to implement the identified actions. High: The initiating Reliability Coordinator violated two of the sub-requirements R3.1, R3.2, and R3.3 as described in the Lower or Moderate VSLs. Severe: The initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level. (R3.1) AND The initiating Reliability Coordinator did not communicate the list of actions to one or more of the required Reliability Coordinators, which are defined as all Eastern Interconnection Reliability Coordinators and any Reliability Coordinators in other Interconnections responsible for curtailing or reloading Interchange Transactions crossing Interconnection boundaries identified in the list of actions. (R3.2) AND The initiating Reliability Coordinator did not request one or more of the Reliability Coordinators identified in R3.3 to implement the identified actions.

Response: The drafting team believes that the language as written is appropriate.

Note that the use of the phrase "some" would be ambiguous if other options were provided and intended to imply a relative scale (e.g., few, some,

Organization	Yes or No	Question 6 Comment
many, etc…). However, the definition of "some" is generally defined as being a part of a set of unspecified size. In this case, the VSL is graded based on ALL actions being taken, SOME actions being taken, or NO actions being taken. SOME, therefore, indicates that at least one action was taken (therefore the entity is has met more than 0% of their obligation), but not all actions were taken (so the entity did not meet 100% of their obligation). We believe that this use, in this context, is appropriate.		
KCPL	No	The term "more effective actions" in the VSL for R1 is too subjective and not auditably supportable. Obviously, the determination of what is "more effective actions" is debatable and can be the cause of controversy in an audit. Recommend either removal or quantifying actions that could be considered "more effective" in Requirement R1, measure M1, and the VSL for R1.
Response: The drafting team has removed the phrase "more effective" from the requirement.		
Southern Company Transmission	No	Please see response to Question #5 Also, the Severe VSL Requirement R5 suggests that an RC's response time of 25 minutes plus one is just as harmful as not responding at all. Has any consideration been given to removing the time component of this VSL?
Response: Please see question 5 for response. The time component of the VSL was included to ensure relief is provided on a timely basis. If that time exceeds 25 minutes, we believe the RC may be unable to seek alternate relief suggestions in a time frame sufficient to avoid mitigate the problem effectively. Therefore, the late provision of this information has little reliability value, and does not meet the intent of the requirement.		
NPCC	No	See our response to Q#4 re. R1.R5 states that the RC must acknowledge to the initiating RC the actions "it will take" within ten minutes, whereas the Lower, Moderate and High VSLs refer to "its [the RC's] actions taken" and the Severe VSL refers to "its actions". These discrepancies in what is to be communicated in our view need to be addressed. We suggest modifying the VSLs by replacing the text in quotes with "the actions it will take" or "the actions it intended to take".
Response: Please see response to question 4. The language regarding "it will take" has been modified in the VSLs to be consistent with the requirement.		

Organization	Yes or No	Question 6 Comment
IESO	No	See our response to Q#4 re. R1.R5 states that the RC must acknowledge to the initiating RC the actions "it will take" within ten minutes, whereas the Lower, Moderate and High VSLs refer to "its [the RC's] actions taken" and the Severe VSL refers to "its actions". These discrepencies in what is to be communicated in our view need to be addressed. We suggest modifying the VSLs by replacing the text in quotes with "the actions it will take" or "the actions it intended to take".
Response: Please see response to question 4. The language regarding “it will take” has been modified in the VSLs to be consistent with the requirement.		
Duke Energy Corporation	No	The VSL for Requirement R1 should have the phrase "more effective" deleted as pointed out in our Comment #4 above.The VSL for Requirement R3 should be revised to place R3.1, R3.2 and R3.3 all under the SEVERE VSL heading. Failure to comply with any of these sub-requirements would result in an overall failure to meet Requirement R3.
Response: The drafting team has removed the phrase “more effective” from R1 and its VSLs. However, the drafting team disagrees with the suggestion that any failure to comply with 3.1, 3.2, or 3.3 should be seen as a severe violation. A failure to implement 3.1 results in a lack of communication, but the remaining actions are the more important actions. If 3.2 is missed, then there is a more detailed lack of communication and coordination regarding what will be happening, but it des not eliminate the action that provides the relief. However, failing 3.3 results in some or all of the requested relief not being provided; hence its High and Severe VSL.		
We Energies	Yes	
American Electric Power	Yes	
FirstEnergy	Yes	
PJM Interconnection	Yes	
Ameren	Yes	

Organization	Yes or No	Question 6 Comment
PacifiCorp		None

7. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standards.**

Summary Consideration: The majority of commenters did not have significant comments. Changes made in response were minor and did not change the intent of the standard.

Some commenters expressed concern regarding the guidelines for establishing the appropriate TLR Level. The SDT made clarifying changes to the standard to make it clear that these are not requirements.

Organization	Question 7 Comment
Midwest ISO Standards Collaborators	IRO-001-1 R8 requires TOPs and BAs to follow RC directives. We are concerned that these standards may be creating potential for double jeopardy because IRO-001-1 R8 already obligates BAs and TOPs to issue curtailments. Does the drafting team believe that issuing a TLR and associated curtailment requirements by the RC not represent an RC directive? We believe the industry may not have a consistent opinion on this position and that some entities could be found in violation of a requirement in these standards and IRO-001-1 R8.We support the drafting team's position regarding use of the TLR in conjunction with other tools to mitigate an IROL that has been exceeded. We believe the Commission is misapplying the conclusions of the Blackout Report.
Response: By virtue of the fact that an RC or BA can respond in the negative if they have a reliability reason to do so, we believe these are not directives.	
MRO NERC Standards Review Subcommittee	We support the drafting team's position regarding use of the TLR in conjunction with other tools to mitigate an IROL that has been exceeded. We believe the Commission is misapplying the conclusions of the Blackout Report.
Response: The drafting team appreciates your supportive comments.	
KCPL	No additional comments.
Southern Company Transmission	Interchange Authorities are not included in the standard. TLR curtailments are often denied by the Interchange Authorities, sometimes in the same reliability region that the TLR has been issued, because the TLR was issued after the time limits programmed into their tagging program. In these cases the relief would not be provided and not due to the inaction of anyone

Organization	Question 7 Comment
	mentioned in this standard. **Response:** Interchange Authorities do not approve or deny transaction modifications; they collect approvals from the Balancing Authorities and the Transmission Service Providers. Additional comments pertain to the proposed IRO-006-EAST-1 standard and the inclusion of Appendix A. It is our recommendation that Appendix A and the reference to it in Requirement R2.1 be deleted from the standard. The language of Appendix A is, in our opinion, overly prescriptive for the actions a Reliability Coordinator is to take with respect to Transmission Loading Relief. Several of the specific concerns we note as problematic in the content of Appendix A: 1) The preamble of Appendix A states its purpose is ... intended to assist the Reliability Coordinator in determining what level of TLR to call and offers that... the Reliability Coordinator has the discretion to choose any of these levels regardless of the criteria listed below .... While the flavor of the preamble suggests no mandatory nature of the listed criteria, Requirement R2.1 does. Picking up from the end of Requirement R2 ... the Reliability Coordinator shall identify: [R2.1] The TLR level in accordance with the criteria in Appendix A, and ....In addition to the deletion of Appendix A, we recommend changing the language of Requirement R2.1 to read: R2.1 The TLR level to be implemented, and.In the event the TLR SDT retains Appendix A – **Response:** The criteria have been specified as guidelines, as indicated in the introduction to the appendix. The goal of the appendix is to provide information and required nomenclature, but not mandatory criteria. Accordingly, the SDT does not believe that the requirement is in conflict with the preamble of the standard. 2) To our knowledge, TLR Level 6 remains an option for utilization by Reliability Coordinators and is referenced in the NAESB WEQ-008 business practice standard. TLR Level 6 is not included in Appendix A. **Response:** The drafting team has returned TLR 6 back to the list. 3) Under TLR Level 1, an eight hour lead time to issue a TLR Level 1 appears to be too long. Three to four hours seems more reasonable. **Response:** As stated above, these criteria are suggested guidelines. As listed in the introduction, an RC “has the discretion to choose any of these levels regardless of the guidelines listed below.” 4) Under TLR Level 5a in the first bullet point, the language ?... when the next-hours transactions start should be changed to...

Organization	Question 7 Comment
	within the next hour. In the second bullet point the language offers an either / or prescription when TLR Level 5 (a or b) curtailments of Non-Firm and Firm transactions, market flows and NNL (in Firm) are sequential in nature non-firm and then firm. We recommend changing the language in the second bullet point to read, Analysis shows the following sequential sets of actions can prevent exceeding the SOL or IROL: The connector or between the two sub-bullet points could then be changed to and (then). **Response:** The drafting team has modified the standard to state "within" the next hour, and replaced the "or" language with "and." 5) The same argument we make in (4) applies to the third bullet point in the TLR Level 5b section of the Appendix. To further illustrate our point, this bullet point offers that Analysis shows that either of the following sets of actions can prevent exceeding the SOL or IROL: with an or connector between the two sub-bullets. This suggests the Reliability Coordinator can choose the second sub-bullet while leaving the provisions of the first sub-bullet in play; i.e., choose to reconfigure the transmission system and curtail Firm while leaving Non-Firm in play. **Response:** The drafting team has modified the standard to replace the "or" language with "and." 6) The original intent of TLR 0 was to simply conclude a TLR event. The criteria shown for TLR 0 in Appendix A significantly adds to the purpose of TLR 0. It causes a Reliability Coordinator to remain in a TLR event until certainty of not approaching, or exceeding, a SOL or IROL eight hours into the future is determined. **Response:** As stated above, these criteria are suggested guidelines. As listed in the introduction, an RC "has the discretion to choose any of these levels regardless of the guidelines listed below." In conclusion, we would like to add that we very much appreciate the work of the Transmission Loading Relief Standard Drafting Team to improve the overall quality of the IRO-006 standards and thank the members of the drafting for their commitment of time and effort in bringing Phase III of their work to fruition. Furthermore, we would like to say that we appreciate the opportunity to comment on this second draft of the proposed versions of the IRO-006 standards.
Response: Please see in-line responses.	
BPA	BPA is in support of standard as written.

Organization	Question 7 Comment
Response: The drafting team appreciates your supportive comments.	
FirstEnergy	1. In the following phrase from the Draft 2 proposed Market Flow definition: "the total amount of generation-to-load impact flowing across a specified facility or set of facilities due to a market dispatch", the term "impact" is vague and does not improve clarity over the terms "energy" or "power" from the original draft of the definition. **Response:** The definition has been clarified as shown below. **Market Flow:** the total amount of energy flowing across a specified Facility or set of Facilities due to a market dispatch of internal generation to serve internal load. 2. Since IRO-006-5 requires compliance with interconnection-specific TLR procedures per requirement R1, it would be helpful if IRO-006-5 Sec. F. "Associated Documents" provided links to IRO-006-EAST-1, IRO-006-WECC-1, and the congestion management procedures from the ERCOT Protocols. **Response:** As these suggested documents are actual standards, there is no need to link to them. The SDT does not believe it is necessary to link to the ERCOT protocols, as they are already easily available from the ERCOT website.
Response: Please see in-line responses.	
NPCC	1. We have a further concern with R1 of IRO-005-EAST-1 that it may result in "premature" load shediding on occasions. For example, in situations where the only "more effective action" that can be taken is load shedding (say because other actions had been used previously to mitigate other exceedances), the RC would be obliged to shed load before being able to (again) initiate the TLR procedure. Shedding load should be a measure of last resort but yet this would have to be done before initiating the TLR procedure since this procedure cannot be used alone to mitigate the exceedance. Can such situations be accounted for **Response:** The SDT has eliminated the “more effective” language form the standard. However, note that R1 does not require an entity to shed load before or after initiating a TLR. The decision to shed load rests with the extent to which an entity can meet requirement R4 of IRO-009 to be under their IROL within their T_v 2. The purpose statement of IRO-006-5 refers to "potential or actual SOL and IROL violations?", whereas the purpose statement of IRO-006-EAST-1 refers to "potential or actual SOL and IROL exceedances". We believe this is an inconsistency and should be

Organization	Question 7 Comment
	addressed by changing "violations" to "exceedances". **Response:** The SDT modified the IRO-006-5 purpose to use the word "exceedances."
Response: Please see in-line responses.	
IESO	1. We have a further concern with R1 of IRO-005-EAST-1 that it may result in "premature" load shediding on occasions. For example, in situations where the only "more effective action" that can be taken is load shedding (say because other actions had been used previously to mitigate other exceedances), the RC would be obliged to shed load before being able to (again) initiate the TLR procedure. Shedding load should be a measure of last resort but yet this would have to be done before initiating the TLR procedure since this procedure cannot be used alone to mitigate the exceedance. Can such situations be catered for **Response:** The SDT has eliminated the "more effective" language form the standard. However, note that R1 does not require an entity to shed load before or after initiating a TLR. The decision to shed load rests with the extent to which an entity can meet requirement R4 of IRO-009 to be under their IROL within their T_v 2. The purpose statement of IRO-006-5 refers to "potential or actual SOL and IROL violations", whereas the purpose statement of IRO-006-EAST-1 refers to "potential or actual SOL and IROL exceedances". We believe this is an inconsistency and should be addressed by changing "violations" to "exceedances". **Response:** The SDT modified the IRO-006-5 purpose to use the word "exceedances."
Response: Please see in-line responses.	
Duke Energy Corporation	The Purpose statement of IRO-006-5 should be revised to more clearly state that the purpose of this standard is to require RC, BA, or TO action on TLRs that seek curtailment or reloading of Interchange Transactions that cross Interconnection boundaries, unless there is a reliability reason not to comply. As currently written, the Purpose statement only incudes Interconnection-wide TLRs.
Response: This standard is intended to address only curtailments related to Interconnection-wide actions and the obligation to agree to curtailment requests unless a reliability reason prevents that agreement. The requirement that interchange transactions and their associated modification, including curtailment, must be agreed to and implemented by all balancing authorities is addressed in the INT family of standards.	
We Energies	IRO-006-5 Purpose: The Purpose may be too broad since the one requirement, R1, only applies to interchange crossing an

Organization	Question 7 Comment
	interconnection boundary. IRO-006-5 R1: As written, R1 REQUIRES a BA to reload an interchange transaction. A BA must always balance resources and demand, even during a TLR. When a TLR is issued that cuts or limits a transaction, the affected BAs still have to comply with the Balancing standards. One has to reduce generation, the other has to acquire other resources to supply its demand. Both have to control ACE. There will generally be no reliability reason requiring a transaction to be reloaded. Requiring a transaction to be reloaded may cause the ACE of one BA to go low because it does not have the generation to support it, and the other BAs ACE to go high because it is receiving MW but does not have load that requires it. Transactions should be allowed to be reloaded at the discretion of the parties involved, but should not be required to be reloaded.
Response: The SDT has updated the purpose statement to better reflect the goals of the standard. The SDT has eliminated “reloading” from the standards.	
American Electric Power	IRO-006-EAST-1: Market Flow: the total amount of generation-to-load impact of energy flowing across a specified facility or set of facilities due to a market dispatch. the operation of a market that has implemented a Market Flow Calculation methodology. We recommend using resource-to-load impact, rather than of generation-to-load impact. **Response:** The SDT believes that the use of the phrase “resource” is unnecessary in this definition. If a resource is not a generation resource, then it will not create energy to serve load. While the term “resource” may be appropriate for describing things such as reserves, the use of the term in this context is not appropriate. R1 mentions including, but not limited to, the following: reconfiguration, redispatch, use of demand-side management, and load shedding, yet R4 does not reference redispatch or generation, when this action, or directive, directly impacts a BAs ability to balance resources to load or demand. A TOP or RC may be giving a directive for redispatch of generation for reliability purposes, but there should also be mention of directing a BA to also implement redispatch requests, as it directly impacts balancing efforts. **Response:** The SDT believes that the last two bullets incorporate the concepts of redispatch. Note that independent of the procedure, an RC may direct redispatch as an independent action. Regardless of whether or not a redispatch directive is received by a Balancing Authority, that entity is still subject to the BAL standards and their associated measures that require balancing.
Response: Please see in-line responses.	

Organization	Question 7 Comment
EPSA	Although EPSA members have no specific suggestions for changes to the proposed standards we have two general concerns with the direction of the standard. R1 of the standard requires the use of other methodologies (such as redispatch, reconfiguration, DSM and load shedding) to eliminate exceedances prior to or in conjunction with TLRs during an IROL exceedance. While we recognize the need for such actions under these circumstances, we encourage the use of the early steps of the TLR procedures with the parallel NAESB standards for dealing with equity issues, to the maximum extent possible, to mitigate situations before the exceedances occur. In addition, we recognize the need for Reliability Coordinators to have the authority to take whatever actions are necessary when an IROL exceedance occurs. **Response:** The SDT will forward this suggestion to NAESB. R4(2) contemplates that under certain circumstances when a TLR has been invoked, that an RC receiving a request for action will have a pre-approved (by the ERO) alternative to implementing the actions requested. Where such a plan has been approved by the ERO as meeting the reliability obligations of that RC, there should be a stakeholder process, such as NAESB's, to deal with the equity implications of the alternative plan. **Response:** The SDT is unaware of any NAESB process for reviewing equity implication of alternative congestion management approaches. We believe this is typically addressed with the FERC through tariffs. However, the SDT has considered this item further, and believe it is more appropriate to be addressed through a variance. As such, the language is being eliminated from the standard. EPSA is also aware that NERC is evaluating potential changes to the IDC that will facilitate alternative approaches in the implementation of TLRs, from an equity point of view. If a determination is made to proceed with IDC changes, we encourage NAESB to initiate expeditiously a review of its TLR Business Practice Standards to insure that the IDC changes are designed to also facilitate any contemplated enhancements to NAESB's standards. **Response:** NERC fully intends to coordinate with NAESB on this issue as it develops further.
Response: Please see in-line responses.	
Entergy Services, Inc.	We have the following suggestions: 1) IRO-006-5 has "Proposed Effective Date" and IRO-006-EAST-1 has "Effective Date". They both should be the same. 2) IRO-006-5 "Proposed Effective Date" has the requirement that "...calendar quarter following....", while IRO-006-EAST-1

Organization	Question 7 Comment
	"Effective Date" has the requirement that "...calendar quarter after...." Both requirements should be "following', or "after". 3) Remove the word "for" in the second line of IRO-006-EAST-1, M3. 4) IRO-006-5 has "Regional Variances" while IRO-006-EAST-1 has "Regional Differences". It seems they both should be the same, either "variances" or "differences". 5) The term "reallocation" should be footnoted in TLR-5b of Appendix A of IRO-006-EAST-1. The footnoting of that term should be the same as the footnoting in TLR-5a.
Response: The SDT has incorporated the suggested changes.	
ISO/RTO Council	We support the drafting team's position regarding use of the TLR in conjunction with other tools to mitigate an IROL that has been exceeded. We believe the Commission is misapplying the conclusions of the Blackout Report.
Response: The drafting team thanks you for your supportive comment.	

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 the SAR and assembled a drafting team on December 5, 2006.
2. The revisions to IRO-006 to transfer business practice content to NAESB were approved as IRO-006-4 by the Board of Trustees on October 23, 2007.
3. The SDT developed a first draft for industry consideration and posted it for comments from October 30, 2008 to December 1, 2008.
4. The SDT developed a second draft for industry consideration and posted it for comments from February 19, 2009 to April 6, 2009.
5. The SDT has developed this third draft for industry consideration.

Description of Current Draft:

This is the third draft of the proposed standard posted for stakeholder comments.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Posting for Comment (Draft 3).	July 13
2. Respond to Comments (Draft 3).	October 8, 2009
3. Posting for 30-day Pre-Ballot Review.	October 8, 2009
4. Initial Ballot.	November 7, 2009
5. Respond to comments.	December 22, 2009
6. Recirculation ballot.	December 22, 2009
7. Board adoption.	January 2010

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.

None.

A. Introduction

1. **Title:** **Reliability Coordination — Transmission Loading Relief (TLR)**

2. **Number:** **IRO-006-5**

3. **Purpose:** To ensure coordinated action between Interconnections when implementing~~provide~~ Interconnection-wide transmission loading relief procedures ~~that can be used~~ to prevent or manage potential or actual SOL and IROL ~~violations~~ exceedances to maintain reliability of the bulk electric system.

4. **Applicability:**

   4.1. Reliability Coordinator.

   ~~4.2.~~Balancing Authority.

   ~~4.3.~~**4.2.** ~~Transmission Operator.~~

5. **Proposed Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Reliability Coordinator ~~or~~and~~,~~ Balancing Authority~~, or Transmission Operator~~ that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, -or Transmission Operator in another Interconnection ~~(or Balancing Authority or Transmission Operator, as appropriate for the neighboring Interconnection)~~ to curtail ~~or reload~~ an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a reliability reason that it cannot comply with the request. [*Violation Risk Factor: ~~Medium~~High*] [*Time Horizon: Real-time Operations*]

C. Measures

M1. Each Reliability Coordinator~~,~~ and Balancing Authority~~, and Transmission Operator~~ shall provide evidence (such as logs, voice recordings, Tag histories, and studies) that, when a request to curtail ~~or reload~~ an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure was made from another Reliability Coordinator, Balancing Authority,~~, Balancing Authority,~~ or Transmission Operator in that other Interconnection, it complied with the request or provided an identified reliability reason that it could not comply with the request.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Reliability Coordinator ~~,~~ and Balancing Authority~~, and Transmission Operator~~ shall ~~-~~each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator~~,~~ and Balancing Authority~~, and Transmission Operator~~ shall each maintain evidence to show compliance with Requirement R1 for the most recent twelve calendar months plus the current month.
- If a Reliability Coordinator~~,~~ or Balancing Authority~~, or Transmission Operator~~ is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				The ~~applicable~~ responsible entity received a request to curtail ~~or reload~~ an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority, or Transmission Operator, but the entity neither complied with the request, nor provided a reliability reason that it could not comply with the request.

E. ~~Regional~~ Variances

None.

F. Associated Documents

G. 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
4		Completed NERC/NAESB split	Revision
5		Removed Attachment 1 and made into a new standard, eliminated unnecessary requirements.	Revision

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~~**Reallocation:** The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.~~ (To be retired.)

Market Flow: the total amount of ~~generation-to-load impact~~ energy flowing across a specified ~~f~~Facility or set of F~~f~~acilities due to a market dispatch of internal generation to serve internal load.

A. Introduction

1. **Title: Transmission Loading Relief Procedure for the Eastern Interconnection**

2. **Number:** IRO-006-EAST-1

3. **Purpose:** To provide an ~~Interconnection~~interconnection-wide transmission loading relief procedure (TLR) for the Eastern Interconnection that can be used to prevent and/or mitigate potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).

4. **Applicability:**

   4.1. Initiating Reliability Coordinators in the Eastern Interconnection.

   4.2. Responding Reliability Coordinators.

5. **Proposed Effective Date:** First day of the first calendar quarter ~~that after~~following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. ~~The Reliability Coordinator shall not use the Eastern Interconnection TLR procedure alone to mitigate an IROL exceedance.~~ When acting or directing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's ~~T_v~~T_V, each Reliability Coordinator shall initiate, prior to or concurrently with the initiation of the Eastern Interconnection ~~this~~ TLR procedure (or continuing management of this procedure if already initiated), one or more of the following actions: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*] ~~other more effective actions~~

- Inter-area redispatch
- Intra-area redispatch of generation
- Reconfiguration of the transmission system
- Voluntary load reductions (e.g., Demand-side Management)
- Involuntary load reductions ~~prior to or in conjunction with the initiation of this TLR procedure (or continuing management of this procedure if already initiated), including, but not limited to, the following: reconfiguration, redispatch, use of demand-side management, and load shedding. [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]~~

R2. When initiating the Eastern Interconnection TLR procedure to prevent or mitigate a SOL or IROL exceedance, and at least every clock hour after initiation~~,~~ up to and including the hour when the TLR level has been identified as TLR Level 0, the Reliability Coordinator shall identify: [*Violation Risk Factor: ~~Medium~~Medium*] [*Time Horizon: Real-time Operations*]

2.1. The TLR level (TLR levels are listed in Appendix A) ~~in accordance with the criteria in Appendix A,~~ and

2.2. A list of ~~action~~congestion management actions to ~~take~~be implemented~~,~~ based on the TLR level chosen.

R3. Upon the identification of the TLR level and a ~~proposal for~~ list of ~~action~~congestion management actions to ~~take~~ be implemented based on the TLR level chosen, the Reliability Coordinator initiating this TLR procedure shall: [*Violation Risk Factor: ~~Medium~~Medium*] [*Time Horizon: Real-time Operations*]

3.1. Notify all Reliability Coordinators in the Eastern Interconnection of the identified TLR level

~~**2.2.**~~Communicate the list of congestion management actions to be implemented~~actions to take~~ to 1.) ~~:~~

~~**2.3.**~~~~A~~all Reliability Coordinators in the Eastern Interconnection, and 2.)

3.2. ~~T~~those Reliability Coordinators in other Interconnections responsible for curtailing ~~or reloading~~ Interchange Transactions crossing Interconnection boundaries identified in the list of ~~action~~congestion management actions.

~~**2.5.**~~Request that ~~the following entities implement~~ the ~~action~~congestion management actions identified in Requirement R2, Part ~~R~~2.2 be implemented by 1.) ~~:~~

~~**2.6.0.**~~~~E~~each Reliability Coordinator associated with a Sink Balancing Authority ~~in the Eastern Interconnection~~ for which Interchange Transactions are to be curtailed, 2.) ~~or reloaded~~

~~**2.7.0.**~~Each Reliability Coordinator~~s~~ associated with a Balancing Authority in the Eastern Interconnection for which Network Integration Transmission Service or Native Load is to be curtailed, and 3.) ~~or reloaded~~

3.3. Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which its Market Flow is to be curtailed. ~~or reloaded.~~

~~**3.0.0.**Each Reliability Coordinators associated with a Balancing Authority in the Eastern Interconnection operating a DC-tie for an Interchange Transaction sinking outside the Eastern Interconnection and crossing an interconnection boundary with an Interchange Transaction to be curtailed or reloaded.~~

R4. Each Reliability Coordinator ~~in the Eastern Interconnection~~ that receives a request as described in Requirement R3, Part ~~R~~3.3. shall comply with the request by taking one or ~~more~~ both of the following ~~three sets of~~ actions: [*Violation Risk Factor: ~~Medium~~High*] [*Time Horizon: Real-time Operations*]

- Implement the communicated ~~action~~congestion management actions requested by the issuing Reliability Coordinator as follows:
  - Direct its Balancing Authorities to implement the Interchange Transaction schedule change requests.
  - Direct its Balancing Authorities to provide the Network Integrated Transmission Service and Native Load schedule changes for which the Balancing Authorities are responsible.
  - ~~o~~Direct its Balancing Authorities to provide the Market Flow schedule changes for which the Balancing Authorities are responsible.
  -
- ~~Implement a procedure pre-approved by the ERO for use by the responding Reliability Coordinator in lieu of implementing some or all of the requested flow reduction~~

~~actions in the first set under Requirement 4, provided that its implementation is expected to achieve the same or greater effect than the flow reduction actions requested in the first set under Requirement R4.~~Implement alternate ~~action~~congestion management actions to those ~~in the first two sets of actions under Requirement R4~~communicated in Requirement R3, provided that:

- Analysis shows that some or all of the ~~action~~congestion management actions ~~in the first two sets of actions under~~ communicated in Requirement R3, Part 3.3 ~~Requirement R4 or the second set of flow reduction actions under Requirement R4~~ will result in a reliability concern or will be ineffective, and
- The alternate ~~action~~congestion management actions have been agreed to by the initiating Reliability Coordinator, and
- Analysis shows that the alternate ~~action~~congestion management actions will not adversely affect reliability.

R5. Each Reliability Coordinator that responds to a TLR event shall acknowledge to the initiating Reliability Coordinator the ~~action~~congestion management actions it will take pursuant to Requirement R4 as soon as possible but not more than ten minutes of receiving the request. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

C. Measures

M1. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that when acting or directing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_v, the ~~Eastern Interconnection TLR procedure was not used alone to mitigate an IROL exceedance, and other more effective actions were initiated prior to or in conjunction with the initiation or continuing management of the TLR procedure~~ Reliability Coordinator -initiated one or more of the actions listed in Requirement R1 prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated)(R1).

M2. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that at the time it initiated the Eastern Interconnection TLR procedure, and at least every clock hour after initiation~~,~~ up to and including the hour when the TLR level was identified as TLR Level 0, the Reliability Coordinator identified both the TLR Level ~~in accordance with Appendix A~~ and a list of ~~flow reduction action~~congestion management actions to ~~take~~ be implemented based on the TLR level chosen (R2).

M3. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that ~~once~~ after it identified a TLR level and ~~for~~ a list of ~~flow reduction action~~congestion management actions to take, it 1.) notified all Reliability Coordinators in the Eastern Interconnection of the TLR Level, 2.) communicated the list of actions to all Reliability Coordinators in the Eastern Interconnection and those Reliability Coordinators in other Interconnections responsible for curtailing ~~or reloading~~ Interchange Transactions crossing Interconnection boundaries identified in the list of ~~flow reduction action~~congestion management actions, and 3.) requested the Reliability Coordinators identified in Requirement R3, Part ~~R~~3.2 ~~the Requirement~~ to implement the ~~flow reduction action~~congestion management actions identified in Requirement R2, Part ~~R~~2.2 (R3).

M4. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that upon receipt of a request ~~to implement proposed actions~~ as described in Requirement R3, the Reliability Coordinator complied with the request by taking ~~did~~ one or ~~more~~ both of the following: 1.) implemented the communicated ~~flow reduction action~~congestion management actions requested by the issuing Reliability Coordinator~~requested actions~~, ~~2.) implemented a n alternative procedure that had been pre-approved by the ERO for use by the responding Reliability Coordinator that would achieve the same or greater effect than in lieu of some or all of the flow reduction actions requested with equal or greater effect than the request actions not being implemented,~~, or ~~3~~2.) implemented alternate ~~flow reduction action~~congestion management actions based on analysis which showed that some or all of the ~~flow reduction action~~congestion management actions ~~in 1 or 2 w~~communicated in Requirement R3 would have resulted in a reliability concern or would have been ineffective, the alternate ~~flow reduction action~~congestion management actions were agreed to by the initiating Reliability Coordinator, and analysis showed that the alternate ~~flow reduction action~~congestion management actions would not adversely affect reliability (R4).

M5. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that within ten minutes of receiving a request to implement ~~flow reduction action~~congestion management actions pursuant to the implementation of the Eastern Interconnection TLR procedure, it acknowledged to the initiating Reliability Coordinator the ~~flow reduction action~~congestion management actions it ~~will~~ was going to take in response to their request.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

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

- The Reliability Coordinator shall maintain evidence to show compliance with R1, R2, R3, R4, and R5 for the past 12 months plus the current month.
- If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

~~1.~~The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

3. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				~~The Reliability Coordinator used the Eastern Interconnection TLR procedure alone to mitigate an IROL exceedance.~~ ~~OR~~ When acting or directing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_v, the Reliability Coordinator did not initiate one or more of the actions listed under R1 ~~other more effective actions~~ prior to or in conjunction with the initiation of ~~this~~ the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated).
R2	The Reliability Coordinator initiating the Eastern ~~interconnection~~ Interconnection TLR procedure missed identifying the TLR Level ~~in accordance with Appendix A~~ and/or a list of ~~flow reduction~~	The Reliability Coordinator initiating the Eastern ~~interconnection~~ Interconnection TLR procedure missed identifying the TLR Level ~~in accordance with Appendix A~~ and/or a list of ~~flow reduction~~	The Reliability Coordinator initiating the Eastern ~~interconnection~~ Interconnection TLR procedure missed identifying the TLR Level ~~in accordance with Appendix A~~ and/or a list of ~~flow reduction~~	The Reliability Coordinator initiating the Eastern ~~interconnection~~ Interconnection TLR procedure missed identifying the TLR Level ~~in accordance with Appendix A~~ and/or a list of ~~flow reduction~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~action~~congestion management actions to take based on the TLR level chosen for one clock hour during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	~~action~~congestion management actions to take based on the TLR level chosen for two clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0,	~~action~~congestion management actions to take based on the TLR level chosen for three clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	~~action~~congestion management actions to take based on the TLR level chosen for four or more clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.~~,~~
R3	The initiating Reliability Coordinator did not notify ~~-~~one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level (~~R~~3.1).	~~Not applicable~~N/A	The initiating Reliability Coordinator did not communicate the list of ~~flow reduction action~~congestion management actions to one or more of the ~~required~~ Reliability Coordinators listed in Requirement R3, Part ~~R~~3.2.~~1 and R3.2.2, which are defined as all Eastern Interconnection Reliability Coordinators and any Reliability Coordinators in other Interconnections responsible for curtailing or reloading Interchange Transactions crossing Interconnection boundaries identified in the list of actions. (R3.2)~~ OR	The initiating Reliability Coordinator requested none of the Reliability Coordinators identified in Requirement R3, Part ~~R~~3.3 to implement the identified flow reduction actions.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			The initiating Reliability Coordinator requested some, but not all, of the Reliability Coordinators identified in Requirement R3, Part ~~R~~3.3 to implement the identified ~~flow reduction action~~congestion management actions.	
R4				The responding Reliability Coordinator did not take one or ~~more~~ both of the following actions: 1.) Implemented the requested ~~flow reduction action~~congestion management actions. ~~2.) Implemented an alternative procedure that had been pre-approved by the ERO for use by the responding Reliability Coordinator that would achieve the same in lieu of some or all of the actions requested with equal or greater effect than the requested flow reduction actions requestednot being implemented~~2.) Implemented alternate congestion management actions based on analysis which showed that some or all of the actions

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				communicated in Requirement R3, Part 3.3 ~~in 1 or 2~~ would have resulted in a reliability concern or would have been ineffective, and that the alternate ~~flow reduction action~~congestion management actions ~~would not adversely affect reliability and~~ were agreed to by the initiating Reliability Coordinator and analysis showed that the alternate ~~flow reduction action~~congestion management actions would not adversely affect reliability~~,~~.
R5	The responding Reliability Coordinator communicated its intended ~~flow reduction~~congestion management ~~actions~~ actions ~~taken~~ to the initiating Reliability Coordinator, but did so more than ten minutes but ~~not more than~~less than or equal to ~~fifteen~~ 15 minutes after receiving the request.	The responding Reliability Coordinator communicated its intended ~~flow reduction action~~congestion management actions ~~taken~~ to the initiating Reliability Coordinator, but did so more than ~~fifteen~~ 15 minutes but ~~not more than~~less than or equal to ~~twenty~~ 20 minutes after receiving the request.	The responding Reliability Coordinator communicated its intended ~~flow reduction action~~congestion management actions ~~taken~~ to the initiating Reliability Coordinator, but did so more than ~~twenty~~ 20 minutes but ~~not more than~~less than or equal to ~~twenty five~~25 minutes after receiving the request.	The responding Reliability Coordinator communicated its intended ~~flow reduction action~~congestion management actions to the initiating Reliability Coordinator, but did so more than ~~twenty five~~25 minutes after receiving the request. OR The responding Reliability Coordinator did not communicate its intended ~~action~~congestion management

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				actions to the initiating Reliability Coordinator.

E. ~~Regional Differences~~ Variances

None.

F. Associated Documents

G. Revision History

Version	Date	Action	Tracking
1		Creation of new standard, incorporating concepts from IRO-006-4 Attachment; elimination of Regional Differences, as the standard allows the use of Market Flow	New

Appendix A

The following ~~criteria~~ guidelines are intended to assist the Reliability Coordinator in determining what level of TLR to call. However, the Reliability Coordinator has the discretion to choose any of these levels regardless of the ~~criteria~~ guidelines listed below, provided the Reliability Coordinator has reliability reasons to take such action.

Level	Guidelines for System Conditions
TLR-1	• At least one Transmission Facility is expected to approach or exceed its SOL or IROL within 8 hours.
TLR-2	• At least one Transmission Facility is approaching or is at its SOL or IROL. ○ Analysis shows that holding new and increasing non-firm Interchange T~~t~~ransactions and energy flows for the next hour can prevent exceeding this SOL or IROL.
TLR-3a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. ○ Analysis shows that full or partial curtailment or reallocation[1] of non-firm Interchange T~~t~~ransactions and energy flows can prevent exceeding this SOL and IROL.
TLR-3b	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. ○ Analysis shows that full or partial curtailment or reallocation[2] of non-firm ~~t~~ Interchange Transactions and energy flows can prevent exceeding this SOL or IROLs.
TLR-4	~~1)~~• At least one Transmission Facility is expected to exceed its SOL or IROL. ~~□~~○ Analysis shows that full curtailment of non-firm ~~transactions~~ Interchange Transactions and energy flows, or reconfiguration of the transmission system can prevent exceeding this SOL or IROL.
TLR-5a	• At least one Transmission Facility is expected to exceed its SOL or IROL ~~when~~ within the next~~-~~ hour~~'s transactions start~~. ~~□~~○ Analysis shows that ~~either of~~ the following ~~sets of~~ actions can prevent exceeding the SOL or IROL: ~~o~~• Full curtailment non-firm Interchange T~~t~~ransactions and energy flows, and~~or~~ • R~~R~~econfiguration of the transmission system, if possible, and~~, and f~~

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[1] "Reallocation" is a term defined within the NAESB TLR standards.

[2] "Reallocation" is a term defined within the NAESB TLR standards.

[3] "Reallocation" is a term defined within the NAESB TLR standards.

	• Full or partial curtailment or reallocation[3] of firm ~~transactions~~ Interchange Transactions and energy flows.
TLR-5b	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. ○ Analysis shows that ~~either of~~ the following ~~sets of~~ actions can prevent exceeding the SOL or IROL: ▪ Full curtailment of non-firm ~~transactions~~ Interchange Transactions and energy flows, ~~or~~ and ▪ Reconfiguration of the transmission system, if possible, and ▪ ~~and f~~Full or partial curtailment or reallocation[4] of firm ~~transactions~~ Interchange Transactions and energy flows.
TLR-6	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL upon the removal from service of a generating unit or another transmission facility.
TLR-0	• No transmission facilities are expected to approach or exceed their SOL or IROL within 8 hours, and the ICM procedure may be terminated

[4] "Reallocation" is a term defined within the NAESB TLR standards.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

~~Implementation Plan for Standard IRO-006-5 (Reliability Coordination — Transmission Loading Relief (TLR)) and IRO-006-EI-1 (Loading Relief Procedure for the Eastern Interconnection)~~

Standards:

IRO-006-5 —~~–~~ Reliability Coordination — Transmission Loading Relief (TLR)

IRO-006-EAST-1 —~~-~~ Transmission Loading Relief Procedure for the Eastern Interconnection

Summary

The NERC TLR Drafting Team has developed IRO-006-5 and IRO-006-EI-1 as iterative and incremental improvements to IRO-006-4. This is one of three phases of Project 2006-08. The first phase, the split of the IRO-006-3 and its associated Attachment 1 into NERC and NAESB standards, was completed and approved by the NERC Board of Trustees on October 23, 2007, and filed with regulatory authorities on December 21, 2008. The second phase, which is intended to address any needed modifications to the standards based on the PJM/MISP/SPP waivers, is currently undergoing Field Testing. This implementation plan addressed the third phase, which is intended to improve the quality of the standards.

The Drafting Team has made significant revisions to the previous IRO-006-4 and Attachment 1:

1. Converted Attachment 1 into a standard solely for the Eastern Interconnection.
2. Transferred requirements from IRO-006 that were primarily focused on Eastern Interconnection practices to the Eastern Interconnection TLR standard.
3. Clarified the roles of entities when responding to curtailment requests from other Interconnections.
4. Removed the requirement that entities comply with the INT standards, as it was redundant.
5. Restructured the Eastern Interconnection TLR standard (previously Attachment 1) to be clearer and specify reliability requirements.
6. Removed the requirement in IRO-006-5 that specified the appropriate methods to utilize within each Interconnection, instead relying on regional standards for the three Interconnections to capture this information.
7. Expanded the applicability of IRO-006-5 to include the ~~Transmission Operator and the~~ Balancing Authority.

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

Modified Standards

IRO-006-4, and associated Attachment 1, should be retired when IRO-006-5 and IRO-006-EI-1 become effective.

The definition of "Reallocation" should be removed from the Glossary when IRO-006-5 and IRO-006-EAST~~I~~-1 become effective.

The Regional Differences within IRO-006-4 should be retired when IRO-006-5 and IRO-006-E~~I~~AST-1 become effective.

Compliance with Standards

Once the standards become effective, the responsible entities identified in the applicability section of the standards must comply with the requirements. These include:

- Reliability Coordinators
- Balancing Authorities

Proposed Effective Date

The standards will become effective on the first day of the first calendar quarter that after the date the standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standards becomes effective on the first day of the first calendar quarter after the date the standards are approved by the NERC Board of Trustees.

Consideration of Comments for the Third Draft of Standard IRO-006-5 and IRO-006-EAST-1 (Project 2006-08)

The Transmission Loading Relief Standard Drafting Team thanks all commenters who submitted comments on the third draft of standard IRO-006-5 and IRO-006-EAST-1 (Project 2006-08). The standards were posted for a 30-day public comment period from July 13, 2009 through August 13, 2009. Stakeholders were asked to provide feedback on the draft standards and associated implementation plan through a special electronic comment form. There were 15 sets of comments, including comments from more than 70 different people from over 50 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Reliability-Coordination-Transmission-Loading-Relief.html

In general, the majority of comments received were supportive of the changes proposed by the drafting team.

Based on stakeholder comments, the SDT made the following changes:

The SDT combined Requirements R4 and R5, and established the time for the Reliability Coordinator to take action as 15 minutes.

The SDT clarified in IRO-006-5, Requirement R1 that an entity must comply with a request to curtail an Interchange Transaction "unless it provides *to the requestor* a reliability reason that it cannot comply with the request."

The drafting team has deleted Appendix A of IRO-006-EAST-1 and instead incorporated the table from the Appendix into Requirement R2. The system conditions were relabeled as examples, a footnote was added to explain the role of the table, and a sentence was added that states "TLR levels are neither required nor expected to be issued in numerical order of level."

The SDT clarified that a Reliability Coordinator's experience may be used to determine if requested TLR actions are appropriate, and made this clear by replacing "analysis" with "assessment" in IRO-006-EAST-1 Requirement R4.

Additionally, the SDT reviewed the use of the verb "direct" in the previous version of the standard. Following discussion regarding the steps of TLR and what is expected to happen in each of those steps, it was determined that the RC is not issuing directives when implementing TLR. The issuance of TLR and the associated instructions to take action are made unilaterally by the Reliability Coordinator(s). Balancing Authorities are expected to review the requests for action and verify that they can be implemented reliably. To the extent they cannot be implemented reliably, Balancing Authorities are expected to work with their Reliability Coordinator in determining the best course of action. For Interchange Transactions, this Balancing Authority discretion is discussed in INT-005-3 R1.1 and INT-006-3 R1.1. For NITS, Native Load, and Market Flow, it is addressed implicitly in IRO-005-3 R6 and TOP-002-2a R4. Accordingly, rather than use the verb "direct," the team has modified the standard to use the verb "instruct."

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2
4.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Manuel Couto	National Grid	NPCC	1
8.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9.	Brian D. Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Greg Mason	Dynegy Generation	NPCC	5
17.	Bruce Metruck	New York Power Authority	NPCC	6
18.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
19.	Robert Pellegrini	The United Illuminating Company	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
22.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck Westbrook	Tx Pre-Schedule & Real Time	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Carol Gerou	MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
2.	Neal Balu	Wisconsin Public Service	MRO	3, 4, 5, 6
3.	Terry Bilke	Midwest ISO	MRO	2
4.	Ken Goldsmith	Alliant Energy	MRO	4
5.	Jim Haigh	WAPA	MRO	1, 6
6.	Terry Harbour	MidAmerican Energy Company	MRO	3, 5, 6, 1
7.	Joe Knight	Great River Energy	MRO	1, 3, 5, 6
8.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
9.	Scott Nickels	Rochester Public Utilties	MRO	4
10.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
11.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Jason L. Marshall	Midwest ISO Standards Collaborators		X								

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Cyrulewski	JDRJC Associates	RFC	8
2.	Jianmei Chai	Consumers Energy	RFC	3, 4, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dave Folk	FirstEnergy	RFC	
2.	Doug Hohlbaugh	FirstEnergy	RFC	

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Jim Case	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Gary Hutson	SMEPA	SERC	1, 3, 5
2.	Steve Fritz	ACES Power Marketing	SERC	6
3.	Gerry Beckerle	Ameren	SERC	1, 3
4.	Eugene Warnecke	Ameren	SERC	1, 3
5.	Joel Wise	TVA	SERC	1, 3, 5, 9
6.	Chad Randall	E. ON US	SERC	1, 3, 5
7.	Brad Young	E. ON US	SERC	1, 3, 5
8.	Fred Krebs	Calpine	SERC	5
9.	Hugh Francis	Southern	SERC	1, 3, 5
10.	Alan Jones	Alcoa	SERC	1, 5
11.	Timmy LeJeune	Louisiana. Generating	SERC	1, 3, 5
12.	Don Reichenbach	Duke	SERC	1, 3, 5
13.	Greg Stone	Duke	SERC	1, 3, 5
14.	Jason Marshall	MISO	SERC	2
15.	Randy Wilkerson	Progress Energy	SERC	1, 3, 5
16.	Ray Phillips	AMEA	SERC	3, 4
17.	Narinder Saini	Entergy	SERC	1, 3
18.	Robert Thomasson	BREC	SERC	1, 3, 5, 9

19.	Barbara Doland	SERC	SERC	10
20.	Wes Davis	SERC	SERC	10
21.	John Troha	SERC	SERC	10

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
8.	Individual	Hugh Francis	Southern Company	X		X		X					
9.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
10.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
11.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
12.	Individual	Bill Harm	PJM		X								
13.	Individual	Dan Rochester	Independent Electricity System Operator		X								
14.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
15.	Individual	Pat Harrington	BC Hydro			X							

1. The drafting team has modified the purpose of IRO-006-5 to read:

To ensure coordinated action between Interconnections when implementing Interconnection-wide transmission loading relief procedures to prevent or manage potential or actual SOL and IROL exceedances to maintain reliability of the bulk electric system.

Do you agree with this modified purpose?

Summary Consideration: The majority of commenters were satisfied with the purpose.

Some entities had concern with the use of the phrase “Interconnection-wide.” The purpose is using the phrase “Interconnection-wide” to address the scope of the congestion management effort. While the SDT recognizes that there may be impacts in other Interconnections, we believe those impacts are related to the transmission loading relief procedure only by virtue of Interchange; moving generation in one interconnection will not aid a transmission loading in another unless it impacts Interchange between the interconnections. Accordingly, the SDT believes this purpose correctly discusses the coordination needed between interconnections when one interconnection implements an interconnection-wide procedure and that procedure curtails schedules that cross the interconnection boundary.

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	No	For the most part agree but believe statement on interconnection wide is misleading. Suggest striking inter-connection wide from the purpose.
Response: The purpose is using the phrase “Interconnection-wide” to address the scope of the congestion management effort. While the SDT recognizes that there may be impacts in other Interconnections, we believe those impacts are related to the transmission loading relief procedure only by virtue of Interchange; moving generation in one interconnection will not aid a transmission loading in another unless it impacts Interchange between the interconnections. Accordingly, the SDT believes this purpose correctly discusses the coordination needed between interconnections when one interconnection implements an interconnection-wide procedure and that procedure curtails schedules that cross the interconnection boundary.		
MRO NERC Standards Review Subcommittee	No	MRO NSRS largely agrees with the modified purpose statement but believes one additional modification is required. Interconnection-wide contradicts that coordination is needed among Interconnections. We suggest striking Interconnection-wide from the purpose. The purpose should then read:"To ensure coordinated action between Interconnections when implementing transmission loading relief procedures to prevent or manage potential or actual SOL and IROL exceedances to maintain reliability of the Bulk Electric System."
Response: The purpose is using the phrase “Interconnection-wide” to address the scope of the congestion management effort. While the SDT		

Organization	Yes or No	Question 1 Comment
recognizes that there may be impacts in other Interconnections, we believe those impacts are related to the transmission loading relief procedure only by virtue of Interchange; moving generation in one interconnection will not aid a transmission loading in another unless it impacts Interchange between the interconnections. Accordingly, the SDT believes this purpose correctly discusses the coordination needed between interconnections when one interconnection implements an interconnection-wide procedure and that procedure curtails schedules that cross the interconnection boundary.		
Midwest ISO Standards Collaborators	No	We largely agree with modified purpose statement but believe one additional modification is required. Interconnection-wide contradicts that coordination is needed among Interconnections. We suggest striking Interconnection-wide from the purpose. The purpose should then read:"To ensure coordinated action between Interconnections when implementing transmission loading relief procedures to prevent or manage potential or actual SOL and IROL exceedances to maintain reliability of the bulk electric system."
Response: The purpose is using the phrase "Interconnection-wide" to address the scope of the congestion management effort. While the SDT recognizes that there may be impacts in other Interconnections, we believe those impacts are related to the transmission loading relief procedure only by virtue of Interchange; moving generation in one interconnection will not aid a transmission loading in another unless it impacts Interchange between the interconnections. Accordingly, the SDT believes this purpose correctly discusses the coordination needed between interconnections when one interconnection implements an interconnection-wide procedure and that procedure curtails schedules that cross the interconnection boundary.		
SERC OC Standards Review Group	No	We suggest removing the words, "Interconnection-wide" and suggest alternative wording to enhance clarity: To ensure coordinated action when implementing transmission loading relief procedures between and among Interconnections to prevent or manage potential or actual SOL and IROL exceedances to maintain reliability of the bulk electric system.
Response: The purpose is using the phrase "Interconnection-wide" to address the scope of the congestion management effort. While the SDT recognizes that there may be impacts in other Interconnections, we believe those impacts are related to the transmission loading relief procedure only by virtue of Interchange; moving generation in one interconnection will not aid a transmission loading in another unless it impacts Interchange between the interconnections. Accordingly, the SDT believes this purpose correctly discusses the coordination needed between interconnections when one interconnection implements an interconnection-wide procedure and that procedure curtails schedules that cross the interconnection boundary.		
American Electric Power	Yes	
BC Hydro	Yes	

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	Yes	
Duke Energy	Yes	
FirstEnergy	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Independent Electricity System Operator	Yes	
Northeast Power Coordinating Council	Yes	
PacifiCorp	Yes	
PJM	Yes	
Southern Company	Yes	

2. The drafting team modified Requirement R1 of IRO-006-5 such that it no longer applies to the Transmission Operator. While requests may still be issued by Reliability Coordinators (as is done in the Eastern Interconnection) or Transmission Operators (as the SDT believes is currently done in the West) or Balancing Authorities (which may be done at some point in the future), the SDT believes that the appropriate entities to respond to those requests are either Balancing Authorities or Reliability Coordinators. Additionally, the SDT has removed ambiguous language from the requirement. Do you agree with these modifications?

Summary Consideration: The majority of commenters agreed with the modifications.

Some commenters expressed a concern that it was not clear who was communicating to whom when giving a reliability reason for not complying with a request. The SDT clarified this language in the standard.

One commenter felt that there needed to be an obligation to act within a certain time frame imposed by the standard. The SDT combined R4 and R5 to provide this obligation, and established the time for the RC to take action as 15 minutes.

Organization	Yes or No	Question 2 Comment
American Electric Power	No	AEP believes that there should be a corresponding relationship between the level of the TLR and the VSL, as the TLR level will provide the severity of action or non-action required.
Response: The SDT disagrees that the TLR Level will have an impact on the Violation Severity Level. The VSL measures the extent to which an entity failed to meet the requirement.		
Southern Company	No	It is our opinion that the Standard Drafting Team (SDT) has not fully developed Requirement R1 in that there is no explicit time period specified within IRO-006-5 for meeting this requirement. Because a thirty minute time period for compliance is prevalent in several approved standards (cited below), we feel Tv or a maximum limit of thirty minutes is appropriate for this standard. The modified language is included below. R1. Each Reliability Coordinator and Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request within Tv but no longer than 30 minutes, unless it provides a reliability reason that it cannot comply with the request. [Violation Risk Factor: High] [Time Horizon: Real-time

Organization	Yes or No	Question 2 Comment
		Operations] The following standards included some mention of a 30 minute limit or Tv limit. IRO-001-1.1 (R3), IRO-009-1 (R4 & R5), TOP-004-2 (R4), TOP-007-0 (R2).
Response: The SDT has combined R4 and R5 and incorporated a 15-minute deadline for the RC to take action into R4 to address this issue. The 15 minute duration was chosen based on current practice, which allows for sufficient time to make adjustments to any Interchange Schedules being curtailed.		
MRO NERC Standards Review Subcommittee	No	MRO NSRS agrees with the changes but notes an additional clarification is needed. R1 requires the RC and BA to comply with a curtailment request "unless it provides a reliability reason that it cannot comply with the request." The reader could infer that this reason must be provided to the issuing RC but the requirement does not explicitly state this. Further, the BA may provide the reason to its RC (assume this RC did not issue TLR) and rely on that RC to communicate it to the issuing RC.
Response: The SDT agrees and has modified the standard to state that an entity must comply "unless it provides to the requestor a reliability reason that it cannot comply with the request."		
Duke Energy	No	The Standards Drafting Team needs to confirm that TOPs in the West may issue requests for loading relief before including the TOP in Requirement R1.
Response: The SDT has spoken with representatives from the West, and believes this is the manner in which WECC procedures are currently handled.		
Midwest ISO Standards Collaborators	Yes	We agree with the changes but note an additional clarification is needed. R1 requires the RC and BA to comply with a curtailment request "unless it provides a reliability reason that it cannot comply with the request." The reader could infer that this reason must be provided to the issuing RC but the requirement does not explicitly state this. Further, the BA may provide the reason to its RC (assume this RC did not issue TLR) and rely on that RC to communicate it to the issuing RC.
Response: The SDT agrees and has modified the standard to state that an entity must comply "unless it provides to the requestor a reliability reason that it cannot comply with the request."		
Manitoba Hydro	Yes	Agree with the changes but note an additional clarification is needed. R1 requires the RC and BA to comply with a curtailment request "unless it provides a reliability reason that it cannot comply with the request." It is still not clear who should be communicating The reader could infer that this reason must be provided to the issuing RC but the requirement does not explicitly state this. Further, the

Organization	Yes or No	Question 2 Comment
		BA may provide the reason to its RC (assume this RC did not issue TLR) and rely on that RC to communicate it to the issuing RC.
Response: The SDT agrees and has modified the standard to state that an entity must comply "unless it provides to the requestor a reliability reason that it cannot comply with the request."		
BC Hydro	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Independent Electricity System Operator	Yes	
Northeast Power Coordinating Council	Yes	
PacifiCorp	Yes	
PJM	Yes	
SERC OC Standards Review Group	Yes	

3. The drafting team has updated the definition of "Market Flow" to read:

Market Flow: the total amount of energy flowing across a specified facility or set of facilities due to a market dispatch of internal generation to serve internal load.

Do you agree with this definition?

Summary Consideration: The majority of commenters agreed with the definition. Minor changes were made as suggested by two of the commenters. The definition was changed as follows:

Market Flow: the total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of internal generation to serve internal load.

Organization	Yes or No	Question 3 Comment
American Electric Power	No	FERC has been very clear regarding the need for DR to be considered as a resource. This definition is narrow and does not include the range of resources that are also subject to dispatch.
Response: The SDT believes that while Demand Response can provide congestion relief, it is not appropriate to be incorporated in this definition. Market Flow includes both supply and demand, and therefore already includes the impact of all DR programs within the calculation of market flow.		
SERC OC Standards Review Group	No	The definition reproduced here is not the same as the definition in the redline version (the redline version has "facility" and "facilities" capitalized). The word "energy" should be replaced with the word "power" because energy denotes power flowing over a specified time.
Response: The SDT has adopted the proposed change.		
Duke Energy	No	The definition would be more clear if the word "energy" was changed to "power" since requests for relief are megawatts and not megawatt-hours.
Response: The SDT has adopted the proposed change.		
BC Hydro	No	The term "Market Flow" seems inappropriate. "Market Flow" suggests inter-area flow from one

Organization	Yes or No	Question 3 Comment
		market, through one or more control areas to another market, but the definition seems to suggest the flow is within a control area to end-use customers in that control area. I suggest that you consider changing the term to "Intra-Market Flow".
Response: The term "market flow" is already in use within three RTOs (PJM, MISO and SPP), and the SDT believes that attempting to modify it now could introduce unnecessary confusion.		
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Midwest ISO Standards Collaborators	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Northeast Power Coordinating Council	Yes	
PacifiCorp	Yes	
PJM	Yes	
Southern Company	Yes	

4. The drafting team has updated Requirement R1 of IRO-006-EAST-1 to clarify if TLR is used in response to an actual IROL exceedance, it must be used "prior to or concurrently with" one or more of five other specific listed mitigation actions. Do you agree with this change?

Summary Consideration: The majority of commenters agreed with the change.

Some entities suggested there may be other options besides those listed, and proposed that the language be less limiting, so as to allow other methods of congestion management to be considered. The SDT believes that the five actions listed are generic actions that can be implemented in multiple ways. As such, it does not believe the list is limiting.

Organization	Yes or No	Question 4 Comment
SERC OC Standards Review Group	No	Confining the available mitigation actions to the set listed in this requirement may damage reliability by preventing creative responses to system challenges.
Response: The SDT believes that the five actions listed are generic actions that can be implemented in multiple ways. As such, it does not believe the list is limiting.		
Duke Energy	No	We disagree with limiting actions to the five bulleted actions. Need to leave other options open.
Response: The SDT believes that the five actions listed are generic actions that can be implemented in multiple ways. As such, it does not believe the list is limiting.		
American Electric Power	Yes	
BC Hydro	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 4 Comment
Hydro-Québec TransEnergie (HQT)	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Midwest ISO Standards Collaborators	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Northeast Power Coordinating Council	Yes	
PacifiCorp	Yes	
PJM	Yes	
Southern Company	Yes	

5. **The drafting team has modified R2 and Appendix A of IRO-006-EAST-1 to make it clear that the criteria specified for TLR levels are guidelines only, not requirements. Do you believe these modifications make it clear that an RC should not be found in violation of R2 if they invoke TLR at a level different than that which the guidelines might recommend?**

Summary Consideration: The majority of commenters agreed with the modifications, but several suggested that the Appendix be removed. The SDT has removed the Appendix and incorporated the critical elements into the standard.

Some commenters suggested that it should be made clear that TLR Levels are not required to be called in a specific order. The SDT added the following language to a footnote for the TLR Level descriptions: "TLR levels are neither required nor expected to be issued in numerical order of level."

Organization	Yes or No	Question 5 Comment
American Electric Power	No	After the modifications, the remaining reporting obligations should be moved from Medium to Low VSL. Additionally, identifying the means of communications will be important to compliance.
Response: The SDT believes that the VSLs are appropriate. If the commenter is instead referring to VRF, the SDT believes that using the TLR level communicates information to other entities regarding the severity of congestion, and therefore is appropriate to be in the "Medium" VRF category.		
Southern Company	No	Complying with one Reliability Standard should not allow someone to violate another Reliability Standard. IRO-001 states that "Reliability Coordinators must have the authority, plans, and agreements in place to immediately direct reliability entities within their Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state."Regardless of the wording or intent, guidelines associated with standards become de facto standards during an audit event. Appendix A should be deleted from the standard and made a separate guideline document.
Response: The SDT is unclear of the conflict with IRO-001 as implied by the commenter. The SDT has removed the Appendix and incorporated the critical elements into the standard.		
MRO NERC Standards Review Subcommittee	No	MRO NSRS believes a statement should be added that reads. "TLR levels are neither required nor expected to be issued in numerical order of level. For example, a TLR Level 3a could be issued

Organization	Yes or No	Question 5 Comment
		without issuing any prior TLR Level 1 or 2."
Response: The SDT has added "TLR levels are neither required nor expected to be issued in numerical order of level."		
Midwest ISO Standards Collaborators	No	We believe a statement should be added that reads. "TLR levels are neither required nor expected to be issued in numerical order of level. For example, a TLR Level 3a could be issued without issuing any prior TLR Level 1 or 2."
Response: The SDT has added "TLR levels are neither required nor expected to be issued in numerical order of level."		
SERC OC Standards Review Group	No	We think clarity would be served by adding the underlined phrase in Appendix A: However, the Reliability Coordinator has the discretion to choose any of these levels in any order desired regardless of the guidelines listed below. Also, it is troubling to note that this set of guidelines is included as an appendix to a regulatory requirement when other situations similar to this (see PER Standards) are reproduced in a standalone document.
Response: The SDT has added "TLR levels are neither required nor expected to be issued in numerical order of level." The SDT has removed the Appendix and incorporated the critical elements into the standard.		
FirstEnergy	Yes	We feel that this begs the question should guidelines even be a part of a standard. It sounds like the drafting team believes there is a strong possibility that an auditor might view these guidelines as requirements. If that is the case, there should be no room for error. These guidelines should be in a stand alone document referenced by the standard so that it is clear they are not requirements.
Response: The SDT has removed the Appendix and incorporated the critical elements into the standard.		
BC Hydro	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 5 Comment
Hydro-Québec TransEnergie (HQT)	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Northeast Power Coordinating Council	Yes	
PJM	Yes	

6. The drafting team has eliminated the IRO-006-EAST-1 requirement originally included in R3 to notify the Eastern Interconnection DC Tie Operator of curtailment requests, as the team believes it is no longer needed and is already implicitly addressed in BAL-001. Do you agree this requirement is no longer needed?

Summary Consideration: The majority of commenters agreed the requirement is no longer needed.

Organization	Yes or No	Question 6 Comment
FirstEnergy	No	Although we agree with the removal of the requirement, we have issues with a reliability requirement that is deemed "implicit" as stated in the question. Requirements, if needed for reliability, must always be explicit.
Response: The comment incorrectly referenced BAL-001. It should have instead referenced BAL-006-1, Requirement R4, which states "Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign." The SDT believes this includes BA's separated by DC Ties, as well as any other adjacent BA.		
Southern Company	No	We feel that communication with the DC Tie Operator is already covered within the standards.We again note the absence of a time requirement for some aspects of TLR within Requirement 3. Our response to Question #2 is repeated below as it regards IRO-006-EAST-1 (R3):It is our opinion that the Standard Drafting Team (SDT) has not fully developed Requirement R3 in that there is no explicit time period specified within IRO-006-EAST-1 for meeting this requirement. While the SDT may be relying on other standards; such as IRO-001-1.1 (R3), IRO-009-1 (R4 & R5), TOP-004-2 (R4), TOP-007-0 (R2) or TOP-008-1 (R1) [Note that IRO-006-EAST-1 is not applicable to Transmission Operators in the case of the last three references], language should be included to mandate a compliance period. The language should be framed to be effective in the absence of a prevailing or superior standard so as not to create a "double jeopardy" non-compliance situation. Since the thirty minute time period for compliance is prevalent in the above references we feel Tv or a maximum limit of thirty minutes is appropriate for this standard.
Response: The SDT has combined R4 and R5 and incorporated a 15-minute deadline into R4 to address this issue. The 15 minute duration was chosen based on current practice, which allows for sufficient time to make adjustments to any Interchange Schedules being curtailed.		
MRO NERC Standards Review Subcommittee	Yes	MRO NSRS agrees the requirement was never needed. RC and BA sources and sinks have always been required to be notified. The sink BA is required to notify all on the transmission path including DC tie operators. However, we don't believe BAL-001 implies that this is addressed.

Organization	Yes or No	Question 6 Comment
Response: The comment incorrectly referenced BAL-001. It should have instead referenced BAL-006-1, Requirement R4, which states "Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign." The SDT believes this includes BA's separated by DC Ties, as well as any other adjacent BA.		
Midwest ISO Standards Collaborators	Yes	We agree the requirement was never needed. RC and BA sources and sinks have always been required to be notified. The sink BA is required to notify all on the transmission path including DC tie operators. However, we don't believe anything in BAL-001 implies that this is addressed.
Response: The comment incorrectly referenced BAL-001. It should have instead referenced BAL-006-1, Requirement R4, which states "Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign." The SDT believes this includes BA's separated by DC Ties, as well as any other adjacent BA.		
American Electric Power	Yes	
BC Hydro	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Northeast Power	Yes	

Organization	Yes or No	Question 6 Comment
Coordinating Council		
PJM	Yes	
SERC OC Standards Review Group	Yes	

7. The drafting team has eliminated the IRO-006-EAST-1 requirement originally included in R4 that allowed for the use of procedures "pre-approved by the ERO…in lieu of implementing some or all of the requested flow reduction actions." The drafting team believes that the process for Variances has replaced the pre-approval of the ERO, and no special process currently exists for acquiring pre-approval save the Variance process. Do you agree that this allowance is no longer needed?

Summary Consideration: The majority of commenters agreed the allowance is no longer needed.

Some entities expressed concern with the use of the word "analysis." The SDT agreed with those concerns and has replaced "analysis" with the word "assessment" in order to allow other sources, such as experience, to be considered in the bulleted list of actions in Requirement R4. For comparison, here are definitions of analysis and assessment:

Analysis - the examination of something in detail in order to understand it better or draw conclusions from it

Assessment - a judgment about something based on an understanding of the situation

Organization	Yes or No	Question 7 Comment
SERC OC Standards Review Group	No	Requirement 4 has several fundamental issues as it is currently worded: No. 1 This change to the requirement seems to allow "on the fly substitution" for interconnection wide congestion management procedure proscriptions during an actual event. This change would damage coordination because other parties in the congestion management event would not necessarily know or understand what the changes were and why they were substituted for the officially recommended actions. This also would tend to dilute and diminish the ability of an adjacent Reliability Coordinator to maintain their wide-area situational awareness. No. 2 The variance process is essentially a regional variance process, while it is possible and likely that a substitute congestion management procedure may cross regional boundaries. No. 3 Approval by the ERO is an artifact (the ERO was called NERC in the previous versions of this standard and the actual approval was by the NERC OC) from the days of voluntary standards. Assuming that the variance process can't be used, what would constitute approval by the ERO in the context of mandatory standards approved by FERC? No. 4 The use of the word "analysis" in the bullets under R4 seems to indicate a formalized process with a study document which we do not believe would be possible in real time.
Response: 1.) The current IRO-006-4 Attachment 1 sections 1.5 and 1.6 allow for deviations from the directed actions in certain cases. The SDT believes		

Organization	Yes or No	Question 7 Comment
the new R4 is consistent with that which is currently allowed under the existing standards. 2.) The SDT disagrees that the variance process is a "regional" process. NERC's rules of procedure allow for both regional variances and entity variances, and entity variances may apply to more than just a single entity. In this case, the SDT would expect that the RC and the associated entities performing the substitute action would jointly seek an entity variance to allow the alternate procedure to be used in lieu of TLR response actions. 3.) The SDT agrees that "approval by the ERO" is ambiguous. Accordingly, we have proposed to remove the language and instead use the Variance process, which will ensure that the alternate process receives appropriate attention prior to its being allowed as a substitute. 4.) The SDT agrees with your concerns regarding the use of the word "analysis," and has replaced it with the word "assessment" in order to allow other sources, such as experience, to be considered.		
Duke Energy	No	We believe that alternate congestion management actions should be pre-approved by the ERO, as provided in Requirement R3 of IRO-006-4.1
Response: The SDT believes that "approval by the ERO" is ambiguous. Accordingly, we have proposed to remove the language and instead use the Variance process, which will ensure that the alternate process receives appropriate attention prior to its being allowed as a substitute.		
Midwest ISO Standards Collaborators	Yes	We agree with the removal. However, we do not believe a variance is necessary in all cases. Fortunately, the drafting team has left R4 flexible enough that the RC can take other action. However, we believe additional modification is necessary to improve this flexibility and reduce compliance burden. We believe that bullets under the implementing an alternate reliability action need to be modified. Analysis is one way to demonstrate that the congestion management actions will be ineffective or result in a reliability concern or adversely affect reliability. However, it is not the only way and this could imply that the RC now has to have a documented study defending their actions. The RCs operational experience and judgment is likely enough reason to take an alternate action. We suggest that the drafting modify these bullets to make clear that the bottom line is the result needs to be equally effective and as long as actual results demonstrate this, no analysis is necessary.
Response: The SDT agrees with your concerns regarding the use of the word "analysis," and has replaced it with the word "assessment" in order to allow other sources, such as experience, to be considered.		
MRO NERC Standards Review Subcommittee	Yes	MRO NSRS agrees with the removal. However, we do not believe a variance is necessary in all cases. Fortunately, the drafting team has left R4 flexible enough that the RC can take other action. However, we believe additional modification is necessary to improve this flexibility and reduce the compliance burden. We believe that bullets under the implementing an alternate reliability action

Organization	Yes or No	Question 7 Comment
		need to be modified. Analysis is one way to demonstrate that the congestion management actions will be ineffective or result in a reliability concern or adversely affect reliability. However, it is not the only way and this could imply that the RC now has to have a documented study defending their actions. The RCs operational experience and judgment is likely enough reason to take an alternate action. We suggest that these bullets be modified to make clear that the bottom line is the result needs to be equally effective and as long as actual results demonstrate this, no analysis is necessary.
Response: The SDT agrees with your concerns regarding the use of the word "analysis," and has replaced it with the word "assessment" in order to allow other sources, such as experience, to be considered.		
American Electric Power	Yes	
BC Hydro	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Northeast Power Coordinating Council	Yes	
PJM	Yes	

Organization	Yes or No	Question 7 Comment
Southern Company	Yes	

8. The drafting team has eliminated the concept of "reloading" from IRO-006-EAST-1. Reliability Coordinators do not direct reloads; they allow them to occur if the operating conditions permit and transmission customers so desire. Accordingly, the team does not believe any requirement to issue reloads is needed. Do you agree that requiring reloads is not needed in the Reliability Standard?

Summary Consideration: The majority of commenters agreed requiring reloads is not needed in the Reliability Standards.

Organization	Yes or No	Question 8 Comment
American Electric Power	No	Reloads need to be evaluated before resuming energy flow to avoid compromising the reliability of the BES.
Response: The SDT agrees that reloads should be evaluated before resuming energy flow. However, the SDT believes this is addressed already in INT-006-2 R1.		
MRO NERC Standards Review Subcommittee	Yes	MRO NSRS agrees that Reloads are not a reliability issue and therefore do not belong in the reliability standards.
Response: The SDT thanks you for your supportive comment.		
Midwest ISO Standards Collaborators	Yes	We agree that Reloads are not a reliability issue and therefore do not belong in the reliability standards.
Response: The SDT thanks you for your supportive comment.		
BC Hydro	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
FirstEnergy	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	

Organization	Yes or No	Question 8 Comment
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Northeast Power Coordinating Council	Yes	
PJM	Yes	
SERC OC Standards Review Group	Yes	
Southern Company	Yes	

9. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standards.

Summary Consideration:

The majority of comments were not significant. Some resulted in minor language changes for clarity or consistency.

One commenter expressed concerns regarding business practices. The SDT referred that entity to the NAESB and FERC forums.

Some entities expressed concern with not having enough time allowed in IRO-006-EAST-1 R5. The SDT combined R4 and R5 and gave entities 15 minutes, rather than 10, to comply.

Organization	Question 9 Comment
FirstEnergy	1. In IRO-006-EAST-1, we do not understand the reason why the Applicability section must state the "Initiating" RC and "Responding" RC. The Requirements are already explicit enough and the applicability should simply state "Reliability Coordinator".2. In IRO-006-5, we do not understand why the VRF was increased from "Medium" to "High". We believe it should remain "Medium".
Response: 1. The SDT believes it is important to make it clear that only Eastern Interconnection RCs are subject to the requirements that apply to initiating RCs, but all RCs (including those in other Interconnections) are subject to the requirements for responding RCs. 2. The VRF was raised to be consistent with previous FERC actions and directives related to this standard.	
Duke Energy	1. IRO-006-EAST-1 Requirement R2.2 is unclear regarding what constitutes the “list of congestion management actions”. Suggest the following alternate wording: A list of congestion management actions to be implemented, which are calculated by the TLR procedure based upon the TLR level chosen. 2. The Standards Drafting Team needs to make sure that all these revisions are coordinated with the NAESB procedures. 3. The red-lined version of IRO-006-EAST-1 is hard to read because Requirements R3 and R4 formatting is mangled.
Response: 1. The SDT had attempted to draft this standard in a more generic fashion such that if the TLR process changes over time, it is less likely that the standard will need to be modified to accommodate the changes.	

Organization	Question 9 Comment
2. NERC and NAESB are currently coordinating closely on the TLR standards, and meeting as a joint standards drafting team on a regular basis. 3. The SDT will work with NERC staff to review the redline.	
BC Hydro	Additional Comments: 1. In R4, the term “Network Integrated Transmission Service” should be changed to “Network Integration Transmission Service” (see Appendix B of FERC Order 890 B (2008-Jun-23 version of the FERC pro-forma Open-Access Transmission Tariff, OATT): http://www.ferc.gov/whats-new/comm-meet/2008/061908/E-1.pdf 2. In R1, the term “Tv” should be defined in the standard because it does not appear in the NERC Glossary (http://www.nerc.com/files/Glossary_12Feb08.pdf; or http://www.nerc.com/files/Glossary_2009April20.pdf). 3. Appendix A should make the priority order for curtailments clearer and make reference to Section 13.6 of the FERC OATT, particularly the following excerpt, However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider’s sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. This would help to avoid costly and time-consuming legal proceedings like the one involving FERC and Northern States Power that resulted in the 1999 Mar 14 ruling by the US Court of Appeal (see: http://caselaw.lp.findlaw.com/data2/circs/8th/983000p.pdf). 4. Appendix A should clearly state that curtailment of Firm Network Load and Firm Native Load (these terms should be defined by pointing to FERCs OATT) should only take place after all relevant Non Firm and Firm inter-market transfers have been curtailed. The following excerpt from the ruling referenced above provides the rationale: Thus, NSP argues, when there exists a power constraint, by providing curtailment to its native/retail consumers on a pro rata basis with wholesale users, NSP will be forced to provide interruptible service to its native/retail consumers. When such power outages occur, a pro rata curtailment will detrimentally affect native/retail consumers who have no other alternatives available to obtain electrical service. NSP urges that when wholesale (point-to-point) customers are curtailed in electrical transmission, the wholesale customer has alternative sources from which to obtain continuous electrical supply, through either the purchase of electricity from another provider, or via their own power generation facilities. 5. Appendix A: Consider having three columns, (1) “Level”, (2) “Guidelines for System Conditions” and (3) “Additional Actions to be Initiated”. As it is now the definition of the TLR level and the actions to take at that level are in the same column. The last column, by including only the actions additional to what would be taken at the “earlier” TLR levels, would highlight the priority order of the actions. The additional actions to be taken at TLR level 6 should be “curtailment of Network Load and Native Load on a pro-rata basis” to make the link to FERC OATT Section 13.6. 6. General: All NERC and NAESB standards relating to Transmission Loading Relief should make reference to the FERC OATT (particularly Section 13.6, “Curtailment of Firm Transmission Service”). The priority order for curtailments should be clearly articulated using the same language used in the FERC OATT (eg, Non-Firm Point-to-Point, Network Integration Transmission Service, NITS, Network Load, Native Load, etc). Since NERC is acting as the FERC ERO, there needs to be

Organization	Question 9 Comment
	clearer links between the OATT and the NERC and NAESB standards. 7. General: A link to the relevant NAESB web page should be provided in the footnotes that all read, “Reallocation is a term defined within the NAESB TLR standards” I find the NAESB website (http://www.naesb.org/default.htm) difficult to navigate and couldn’t find a glossary, but only many documents related to meeting agendas of the Glossary committee. The NAESB TLR Group page (http://www.naesb.org/weq/weq_tlr.asp) doesn’t appear to have any documents newer than 2005 Jun 28.
Response: 1. The SDT has modified the language as suggested. 2. The term is defined in the glossary under “IROL T_V” 3. The SDT believes these business rules are currently addressed in NAESB standards and FERC Orders, and suggests that the commenter work through those organizations to effect changes if such changes are desired. 4. The SDT believes these business rules are currently addressed in NAESB standards and FERC Orders, and suggests that the commenter work through those organizations to effect changes if such changes are desired. 5. The attachment is not specifying the actions to take, but rather serves as a guideline to determine the appropriate level of TLR. In this particular case, the guidance is based on what actions could be expected to mitigate the scenario. 6. The reliability standard does not make reference to curtailment priority. Curtailment priorities are stipulated in NAESB’s business practices and FERC Orders. 7. To access specific NAESB standards, please contact NAESB (www.naesb.org) for details.	
MRO NERC Standards Review Subcommittee	MRO NSRS is concerned that reliability reason is the only reason allowed for not complying with R1 in IRO-006-5. Unfortunately, the IDC allows an RC to issue a TLR that requires curtailments in the past and MISO has actually received requests for curtailments with effective times that are in the past. R1 could be modified to allow other reasons for not complying with the request such as this or another requirement could be written that requires a reasonable lead time on issuing TLRs and expected time of implementation of cuts. **Response: The NERC IDCWG has been investigating this issue and has made some changes to the IDC that may help address this problem.** Since this standard is for the Eastern Interconnection only, MRO NSRS asks the SDT to write the Measurements to consider presentation of IDC logs and screens as satisfactory evidence. Specifically, we ask the drafting team to modify M2 and M3 IRO-006-EAST-1 to clarify that providing the TLR history from the IDC will satisfy the evidence requirements. Since no RC ever issues a TLR without the IDC, MRO NSRS asks the SDT to write the requirements with consideration of

Organization	Question 9 Comment
	the use of the IDC. For example, R3 should be clarified that the IDC can be relied upon to communicate the notifications. The RC should not be required to demonstrate that the notifications went out as appropriate or essentially that the IDC worked as design. **Response: In previous postings, commenters have agreed that the standard should not reference any specific tool. The IDC is the name of the NERC tool that is currently used to manage the TLR process and is a way, but not necessarily the only way, to show compliance.** MRO NSRS suggests the wording for the third sub-bullet under the first bullet of IRO-006-EAST-1 R4 be changed from:"provide the Market Flow schedule changes"to:"achieve the Market Flow relief obligations". The term "provide" could be misinterpreted. **Response: The SDT has replaced the word "provide" with "implement" to address your concerns.** In IRO-006-EAST-1 R5, the words "as soon as possible but not more than" are problematic from a compliance perspective. How do you prove you did it as soon as possible? If you could have done it 5 seconds sooner, this could be construed as a violation unnecessarily. The MRO NSRS suggests changing this phrase to "within". **Response: The "as soon as possible" language is intended to communicate a sense of urgency, which is appropriate. The language is not included in the measures and is not included in the VSLs.** With regard to IRO-006-EAST-1 R5, there needs to be a documented exemption for tool performance issues. Often there is a 3 minute latency for receiving TLR curtailments from the time they are issued. This leaves only 7 minutes for the RC to review, determine impacts, communicate internally and with the initiating RC, if necessary, to make alternate arrangements, and acknowledge the curtailments. **Response: The SDT has eliminated R5 and incorporated a 15-minute deadline into R4 to address this issue.** Similarly, it should be stated that initiating discussions with the initiating RC regarding the curtailments counts as acknowledgement. **Response: The SDT has eliminated R5 and incorporated a 15-minute deadline into R4 to address this issue.** R5 needs to be further modified to allow 15 minutes rather than 10 for acknowledgement.

Organization	Question 9 Comment
	Response: The SDT has eliminated R5 and incorporated a 15-minute deadline into R4 to address this issue.
Response: Please see in-line responses.	
Northeast Power Coordinating Council	NPCC appreciates the work of the Drafting Team, and has no additional comments.
Response: The SDT thanks you for your supportive comment.	
Independent Electricity System Operator	The drafting team has adequately addressed our comments on the previous draft. Thank you.
Response: The SDT thanks you for your supportive comment.	
SERC OC Standards Review Group	The language in IRO-006-East-1 is too detailed in the "how to" for managing SOL and IROL events. This level of detail is more properly contained in a procedural document. Mandatory enforceable standards should describe "what" is required and at a higher level than described in this current document. **Response: The SDT does not believe that this standard describes the "how" for managing SOL and IROL events; there are other standards that address managing SOL and IROL events. TLR is only one of the measures that can be used to manage congestion. The SDT generally agrees that standards should stipulate the "what," but there are certain procedures which, if they must be performed in a specific fashion to ensure reliability, should be stipulated as reliability standards.** We suggest that the second bullet of R4 in IRO-006-1 should be rewritten to begin as follows: "With the agreement of the initiating Reliability Coordinator, implement alternate congestion management actions to those communicated in Requirement R3, provided that:" If the drafting team agrees with this change the second sub-bullet of the second bullet may be deleted as it may now be redundant. **Response: The SDT agrees that this change could be made, but does not feel that it adds any significant benefit or clarity.** The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.

Organization	Question 9 Comment
Response: Please see in-line responses.	
Midwest ISO Standards Collaborators	We are concerned that reliability reason is the only reason allowed for not complying with R1 in IRO-006-5. Unfortunately, the IDC allows an RC to issue a TLR that requires curtailments in the past and we have actually received requests for curtailments with effective times that are in the past. R1 could be modified to allow other reasons for not complying with the request such as this or another requirement could be written that requires a reasonable lead time on issuing TLRs and expected time of implementation of cuts. **Response: The NERC IDCWG has been investigating this issue and has made some changes to the IDC that may help address this problem.** Since this standard is for the Eastern Interconnection only, we ask the SDT to write the Measurements to consider presentation of IDC logs and screens as satisfactory evidence. Specifically, we ask the drafting team to modify M2 and M3 IRO-006-EAST-1 to clarify that providing the TLR history from the IDC will satisfy the evidence requirements. Since no RC ever issues a TLR without the IDC, we ask the SDT to write the requirements with consideration of the use of the IDC. For example, R3 should be clarified that the IDC can be relied upon to communicate the notifications. The RC should not be required to demonstrate that the notifications went out as appropriate or essentially that the IDC worked as design. **Response: In previous postings, commenters have agreed that the standard should not reference any specific tool. The IDC is the name of the NERC tool that is currently used to manage the TLR process and is a way, but not necessarily the only way, to show compliance.** We suggest the wording for the third sub-bullet under the first bullet of IRO-006-EAST-1 R4 be changed from:"provide the Market Flow schedule changes"to:"achieve the Market Flow relief obligations". Provide could be misinterpreted. **Response: The SDT has replaced the word “provide” with “implement” to address your concerns.** In IRO-006-EAST-1 R5, the words “as soon as possible but not more than” are problematic from a compliance perspective. How do you prove you did it as soon as possible? If you could have done it 5 seconds sooner, this could be construed as a violation unnecessarily. We suggest changing this phrase to “within”. **Response: The “as soon as possible” language is intended to communicate a sense of urgency, which is appropriate. The language is not included in the measures or the VSLs.**

Organization	Question 9 Comment
	With regard to IRO-006-EAST-1 R5, there needs to be a documented exemption for tool performance issues. Often there is a 3 minute latency for receiving TLR curtailments from the time they are issued. This leaves only 7 minutes for the RC to review, determine impacts, communicate internally and with the initiating RC, if necessary, to make alternate arrangements, and acknowledge the curtailments. **Response: The SDT has eliminated R5 and incorporated a 15-minute deadline into R4 to address this issue.** Similarly, it should be stated that initiating discussions with the initiating RC regarding the curtailments counts as acknowledgement. **Response: The SDT has eliminated R5 and incorporated a 15-minute deadline into R4 to address this issue.** R5 needs to be further modified to allow 15 minutes rather than 10 for acknowledgement. **Response: The SDT has eliminated R5 and incorporated a 15-minute deadline into R4 to address this issue.**
Response: Please see in-line responses.	

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 the SAR and assembled a drafting team on December 5, 2006.
2. The revisions to IRO-006 to transfer business practice content to NAESB were approved as IRO-006-4 by the Board of Trustees on October 23, 2007.
3. The SDT developed a first draft for industry consideration and posted it for comments from October 30, 2008 to December 1, 2008.
4. The SDT developed a second draft for industry consideration and posted it for comments from October 30, 2008 to December 1, 2008.
5. The SDT developed a third draft for industry consideration and posted it for comments from July 13, 2009 to August 13, 2009.
6. The SDT has developed this fourth draft for industry consideration.

Description of Current Draft:

This is the fourth draft of the proposed standard posted for stakeholder comments.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
Posting for Comment (Draft 4).	October 30, 2009
Respond to Comments (Draft 4).	January 8, 2010
Posting for 30-day Pre-Ballot Review.	January 8, 2010
Initial Ballot.	February 7, 2010
Respond to comments.	March 31, 2010
Recirculation ballot.	March 31, 2010
Board adoption.	May 2010

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.

None.

A. Introduction

1. **Title: Reliability Coordination — Transmission Loading Relief (TLR)**
2. **Number: IRO-006-5**
3. **Purpose:** To ensure coordinated action between Interconnections when implementing Interconnection-wide transmission loading relief procedures to prevent or manage potential or actual SOL and IROL exceedances to maintain reliability of the bulk electric system.
4. **Applicability:**

   4.1. Reliability Coordinator.

   4.2. Balancing Authority.
5. **Proposed Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Reliability Coordinator or Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a reliability reason to the req~~e~~uest~~o~~er that it cannot comply with the request. [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall provide evidence (such as logs, voice recordings, Tag histories, and studies) that, when a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure was made from another Reliability Coordinator, Balancing Authority, or Transmission Operator in that other Interconnection, it complied with the request or provided an identified reliability reason that it could not comply with the request.

D. Compliance

8. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

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

- The Reliability Coordinator and Balancing Authority shall maintain evidence to show compliance with R1 for the most recent twelve calendar months plus the current month.
- If a Reliability Coordinator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				The responsible entity received a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority, or Transmission Operator, but the entity neither complied with the request, nor provided a reliability reason that it could not comply with the request.

E. Regional Variances

None.

F. Associated Documents

G. 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
4	October 23, 2007	Completed NERC/NAESB split	Revision
5		Removed Attachment 1 and made into a new standard, eliminated unnecessary requirements and variances.	Revision

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~~**Reallocation:** The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.~~ (To be retired.)

Market Flow: the total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of internal generation to serve internal load.

A. Introduction

1. **Title: Transmission Loading Relief Procedure for the Eastern Interconnection**
2. **Number:** IRO-006-EAST-1
3. **Purpose:** To provide an Interconnection-wide transmission loading relief procedure (TLR) for the Eastern Interconnection that can be used to prevent and/or mitigate potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).
4. **Applicability:**
   - **4.1.** Initiating Reliability Coordinators in the Eastern Interconnection.
   - **4.2.** Responding Reliability Coordinators
5. **Proposed Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. When acting or ~~directing~~ instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_V, each Reliability Coordinator shall initiate, prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated), one or more of the following actions: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

- Inter-area redispatch
- Intra-area redispatch of generation
- Reconfiguration of the transmission system
- Voluntary load reductions (e.g., Demand-side Management)
- Involuntary load reductions

R2. When initiating the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance, and at least every clock hour after initiation up to and including the hour when the TLR level has been identified as TLR Level 0, the Reliability Coordinator shall identify: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

2.1. The TLR level ~~(TLR levels are listed in Appendix A)~~as listed below in Table 1, and

2.2. A list of congestion management actions to be implemented based on the TLR level chosen.

TABLE 1 – TLR LEVELS[1]	
Level	**Examples of Possible System Conditions**
TLR-1	• At least one Transmission Facility is expected to approach or exceed its SOL or IROL within 8 hours.
TLR-2	• At least one Transmission Facility is approaching or is at its SOL or IROL. o Analysis shows that holding new and increasing non-firm Interchange Transactions and energy flows for the next hour can prevent exceeding this SOL or IROL.
TLR-3a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. o Analysis shows that full or partial curtailment or reallocation[2] of non-firm Interchange Transactions and energy flows can prevent exceeding this SOL and IROL.
TLR-3b	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. o Analysis shows that full or partial curtailment or reallocation[3] of non-firm Interchange Transactions and energy flows can prevent exceeding this SOL or IROLs.
TLR-4	• At least one Transmission Facility is expected to exceed its SOL or IROL. o Analysis shows that full curtailment of non-firm Interchange Transactions and energy flows, or reconfiguration of the transmission system can prevent exceeding this SOL or IROL.
TLR-5a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. o Analysis shows that the following actions can prevent exceeding the SOL or IROL: • Full curtailment non-firm Interchange Transactions and energy flows, and • Reconfiguration of the transmission system, if possible, and • Full or partial curtailment or reallocation[4] of firm Interchange Transactions and energy flows.
TLR-5b	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. o Analysis shows that the following actions can prevent exceeding the SOL or IROL: ▪ Full curtailment of non-firm Interchange Transactions and energy flows, and ▪ Reconfiguration of the transmission system, if possible, and ▪ Full or partial curtailment or reallocation[5] of firm Interchange Transactions and energy flows.
TLR-6	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL upon the removal from service of a generating unit or another transmission facility.
TLR-0	• No transmission facilities are expected to approach or exceed their SOL or IROL within 8 hours, and the ICM procedure may be terminated

R3. Upon the identification of the TLR level and a list of congestion management actions to be implemented based on the TLR level chosen, the Reliability Coordinator initiating this TLR procedure shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

3.1. Notify all Reliability Coordinators in the Eastern Interconnection of the identified TLR level

[1] The listed system conditions examples are intended to assist the Reliability Coordinator in determining what level of TLR to call. The Reliability Coordinator has the discretion to choose any of these levels regardless of the examples listed, provided the Reliability Coordinator has reliability reasons to take such action. TLR levels are neither required nor expected to be issued in numerical order of level.

[2,3,4,5] "Reallocation" is a term defined within the NAESB TLR standards.

3.2. Communicate the list of congestion management actions to be implemented to

1.) ~~all~~ All Reliability Coordinators in the Eastern Interconnection, and

2.) ~~those~~ Those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions.

3.3. Request that the congestion management actions identified in Requirement R2, Part 2.2 be implemented by

1.) ~~e~~Each Reliability Coordinator associated with a Sink Balancing Authority for which Interchange Transactions are to be curtailed,

2.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which Network Integration Transmission Service or Native Load is to be curtailed, and

3.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which its Market Flow is to be curtailed

R4. Each Reliability Coordinator that receives a request as described in Requirement R3, Part 3.3. shall within 15 minutes of receiving the request comply with the request by taking one or both of the following actions: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

- Implement the communicated congestion management actions requested by the issuing Reliability Coordinator as follows:
  - Instruct~~Direct~~ its Balancing Authorities to implement the Interchange Transaction schedule change requests.
  - ~~Direct~~ Instruct its Balancing Authorities to ~~provide~~ implement the Network Integration ~~ed~~ Transmission Service and Native Load schedule changes for which the Balancing Authorities are responsible.
  - ~~Direct~~ Instruct its Balancing Authorities to ~~provide~~ implement the Market Flow schedule changes for which the Balancing Authorities are responsible.
- Instruct i~~I~~mplementation of alternate congestion management actions to those communicated in R3, provided that:
  - Assessment~~nalysis~~ ~~shows~~ determines that some or all of the congestion management actions communicated in Requirement R3, Part 3.3 will result in a reliability concern or will be ineffective, and
  - The alternate congestion management actions have been agreed to by the initiating Reliability Coordinator, and
  - ~~Analysis~~ Assessment shows that the alternate congestion management actions will not adversely affect reliability.

~~Each Reliability Coordinator that responds to a TLR event shall acknowledge to the initiating Reliability Coordinator the actions it will take pursuant to Requirement R4 as soon as possible but not more than ten minutes of receiving the request. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]~~

C. Measures

M1. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that when acting or ~~directing~~ instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's Tv, the Coordinator initiated one or more of the actions listed in R1 prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated)(R1).

M2. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that at the time it initiated the Eastern Interconnection TLR procedure, and at least every clock hour after initiation up to and including the hour when the TLR level was identified as TLR Level 0, the Reliability Coordinator identified both the TLR Level and a list of congestion management actions to be implemented based on the TLR level chosen (R2).

M3. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that after it identified a TLR level and a list of congestion management actions to take, it 1.) notified all Reliability Coordinators in the Eastern Interconnection of the TLR Level, 2.) communicated the list of actions to all Reliability Coordinators in the Eastern Interconnection and those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions, and 3.) requested the Reliability Coordinators identified in Requirement R3, Part 3.2 to implement the congestion management actions identified in Requirement R2, Part 2.2 (R3).

M4. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that within fifteen minutes of the~~upon~~ receipt of a request as described in R3, the Reliability Coordinator complied with the request by taking one or both of the following: 1.) implemented the communicated congestion management actions requested by the issuing Reliability Coordinator, or 2.) implemented alternate congestion management actions based on ~~a~~assessment ~~nalysis~~which showed that some or all of the congestion management actions communicated in R3 would have resulted in a reliability concern or would have been ineffective, the alternate congestion management actions were agreed to by the initiating Reliability Coordinator, and aassessment~~nalysis~~ showed that the alternate congestion management actions would not adversely affect reliability (R4).

~~**M5.** Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that within ten minutes of receiving a request to implement flow reduction actions pursuant to the implementation of the Eastern Interconnection TLR procedure, it acknowledged to the initiating Reliability Coordinator the flow reduction actions it will take in response to their request.~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

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

- The Reliability Coordinator shall maintain evidence to show compliance with R1, R2, R3, ~~R4,~~ and ~~R5~~ R4 for the past 12 months plus the current month.
- If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

1. The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

3. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				When acting or ~~directing~~ instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_v, the Reliability Coordinator did not initiate one or more of the actions listed under R1 prior to or in conjunction with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated).
R2	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take based on the TLR level chosen for one clock hour during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take based on the TLR level chosen for two clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0,	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take based on the TLR level chosen for three clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take based on the TLR level chosen for four or more clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.
R3	The initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level (3.1).	N/A	The initiating Reliability Coordinator did not communicate the list of congestion management actions to one or more of the Reliability Coordinators listed in Requirement R3, Part 3.2. OR	The initiating Reliability Coordinator requested none of the Reliability Coordinators identified in Requirement R3, Part 3.3 to implement the identified congestion management actions.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			The initiating Reliability Coordinator requested some, but not all, of the Reliability Coordinators identified in Requirement R3, Part 3.3 to implement the identified congestion management actions.	
R4				The responding Reliability Coordinator did not take one or both of the following actions within 15 minutes of receiving a request: 1.) Implemented the requested congestion management actions. 2.) Implemented alternate congestion management actions based on ~~analysis~~ assessment which showed that some or all of the actions communicated in Requirement R3, Part 3.3 would have resulted in a reliability concern or would have been ineffective, and that the alternate congestion management actions were agreed to by the initiating Reliability Coordinator and ~~analysis~~assessment ~~showed~~ determined that the alternate congestion management actions would not adversely affect reliability.
~~R5~~	~~The responding Reliability Coordinator communicated its flow reduction actions taken to the initiating Reliability Coordinator, but did so more than ten minutes but not more thanless than or equal to fifteen 15 minutes after receiving the~~	~~The responding Reliability Coordinator communicated its flow reduction actions taken to the initiating Reliability Coordinator, but did so more than fifteen 15 minutes but not more thanless than or equal to twenty 20 minutes after receiving~~	~~The responding Reliability Coordinator communicated its flow reduction actions taken to the initiating Reliability Coordinator, but did so more than twenty 20 minutes but not more thanless than or equal to twenty five25 minutes after~~	~~The responding Reliability Coordinator communicated its flow reduction actions to the initiating Reliability Coordinator, but did so more than twenty five25 minutes after receiving the request.~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~request.~~	~~the request.~~	~~receiving the request.~~	~~OR~~ ~~The responding Reliability Coordinator did not communicate its actions to the initiating Reliability Coordinator.~~

E. Regional Variances

None.

F. Associated Documents

G. Revision History

Version	Date	Action	Tracking
1		Creation of new standard, incorporating concepts from IRO-006-4 Attachment; elimination of Regional Differences, as the standard allows the use of Market Flow	New

~~Appendix A~~

~~The following criteria guidelines are intended to assist the Reliability Coordinator in determining what level of TLR to call. However, the Reliability Coordinator has the discretion to choose any of these levels regardless of the criteria guidelines listed below, provided the Reliability Coordinator has reliability reasons to take such action. TLR levels are neither required nor expected to be issued in numerical order of level.~~

~~Level~~	~~Guidelines for System Conditions~~
~~TLR-1~~	• ~~At least one Transmission Facility is expected to approach or exceed its SOL or IROL within 8 hours.~~
~~TLR-2~~	• ~~At least one Transmission Facility is approaching or is at its SOL or IROL.~~ o ~~Analysis shows that holding new and increasing non-firm Interchange Ttransactions and energy flows for the next hour can prevent exceeding this SOL or IROL.~~
~~TLR-3a~~	• ~~At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour.~~ o ~~Analysis shows that full or partial curtailment or reallocation~~[3] ~~of non-firm Interchange Ttransactions and energy flows can prevent exceeding this SOL and IROL.~~
~~TLR-3b~~	• ~~At least one Transmission Facility is exceeding its SOL or IROL, or~~ • ~~At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour.~~ o ~~Analysis shows that full or partial curtailment or reallocation~~[4] ~~of non-firm t Interchange Transactions and energy flows can prevent exceeding this SOL or IROLs.~~
~~TLR-4~~	~~1) At least one Transmission Facility is expected to exceed its SOL or IROL.~~ o ~~Analysis shows that full curtailment of non-firm transactions Interchange Transactions and energy flows, or reconfiguration of the transmission system can prevent exceeding this SOL or IROL.~~
~~TLR-5a~~	• ~~At least one Transmission Facility is expected to exceed its SOL or IROL when within the next hour's transactions start.~~ o ~~Analysis shows that either of the following sets of actions can prevent exceeding the SOL or IROL:~~ • ~~Full curtailment non-firm Interchange Ttransactions and energy flows, andor~~ ~~RReconfiguration of the transmission system, if~~

[3] "Reallocation" is a term defined within the NAESB TLR standards.

[4] "Reallocation" is a term defined within the NAESB TLR standards.

	~~possible, and, and f~~ • ~~Full or partial curtailment or reallocation~~[5] ~~of firm transactions Interchange Transactions and energy flows.~~
~~TLR-5b~~	• ~~At least one Transmission Facility is exceeding its SOL or IROL, or~~ • ~~At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour.~~ o ~~Analysis shows that either of the following sets of actions can prevent exceeding the SOL or IROL:~~ ▪ ~~Full curtailment of non-firm transactions Interchange Transactions and energy flows, or and~~ ~~Reconfiguration of the transmission system, if possible, and~~ ▪ ~~and fFull or partial curtailment or reallocation~~[6] ~~of firm transactions Interchange Transactions and energy flows.~~
~~TLR-6~~	~~At least one Transmission Facility is exceeding its SOL or IROL, or~~ • ~~At least one Transmission Facility is expected to exceed its SOL or IROL upon the removal from service of a generating unit or another transmission facility.~~
~~TLR-0~~	• ~~No transmission facilities are expected to approach or exceed their SOL or IROL within 8 hours, and the ICM procedure may be terminated~~

[5] "Reallocation" is a term defined within the NAESB TLR standards.

[6] "Reallocation" is a term defined within the NAESB TLR standards.

Implementation Plan for Standard IRO-006-5 (Reliability Coordination — Transmission Loading Relief (TLR)) and IRO-006-EI-1 (Loading Relief Procedure for the Eastern Interconnection)

Standards~~:~~

IRO-006-5 — Reliability Coordination — Transmission Loading Relief (TLR)
IRO-006-EAST-1 — Transmission Loading Relief Procedure for the Eastern Interconnection

~~Summary~~

~~The NERC TLR Drafting Team has developed IRO-006-5 and IRO-006-EI-1 as iterative and incremental improvements to IRO-006-4. This is one of three phases of Project 2006-08. The first phase, the split of the IRO-006-3 and its associated Attachment 1 into NERC and NAESB standards, was completed and approved by the NERC Board of Trustees on October 23, 2007, and filed with regulatory authorities on December 21, 2008. The second phase, which is intended to address any needed modifications to the standards based on the PJM/MISP/SPP waivers, is currently undergoing Field Testing. This implementation plan addressed the third phase, which is intended to improve the quality of the standards. The Drafting Team has made significant revisions to the previous IRO-006-4 and Attachment 1:~~

1. ~~Converted Attachment 1 into a standard solely for the Eastern Interconnection.~~
2. ~~Transferred requirements from IRO-006 that were primarily focused on Eastern Interconnection practices to the Eastern Interconnection TLR standard.~~
3. ~~Clarified the roles of entities when responding to curtailment requests from other Interconnections.~~
4. ~~Removed the requirement that entities comply with the INT standards, as it was redundant.~~
5. ~~Restructured the Eastern Interconnection TLR standard (previously Attachment 1) to be clearer and specify reliability requirements.~~
6. ~~Removed the requirement in IRO-006-5 that specified the appropriate methods to utilize within each Interconnection, instead relying on regional standards for the three Interconnections to capture this information.~~
7. ~~Expanded the applicability of IRO-006-5 to include the Balancing Authority.~~

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved or in progress, that must be implemented before this standard can be implemented.

Modified Definitions

The definition of "Reallocation" should be removed from the Glossary when IRO-006-5 and IRO-006-EI-1 become effective.

Modified Standards

IRO-006-4, and associated Attachment 1, should be retired when IRO-006-5 and IRO-006-EI-1 become effective.

~~The definition of "Reallocation" should be removed from the Glossary when IRO-006-5 and IRO-006-EI-1 become effective.~~

The Regional Differences within IRO-006-4 should be retired when IRO-006-5 and IRO-006-EI-1 become effective.

Compliance with Standards

Once the standards become effective, the responsible entities identified in the applicability section of the standards must comply with the requirements. These include:

- Reliability Coordinators
- Balancing Authorities

Proposed Effective Date

The standards will become effective on the first day of the first calendar quarter ~~that~~ after the date the standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standards becomes effective on the first day of the first calendar quarter after the date the standards are approved by the NERC Board of Trustees.

Consideration of Comments on IRO-006-5 and IRO-006-EAST-1 (Project 2006-08)

The Transmission Loading Relief Standard Drafting Team thanks all commenters who submitted comments on the current drafts of IRO-006-5 and IRO-006-EAST-1. These standards were posted for a 30-day public comment period from October 27, 2009 through November 30, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 15 sets of comments, including comments from 70 different people from over 40 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Several minor changes were made to the standards based on suggestions received during the comment period:

- Several entities suggested that it be clear that Reliability Coordinators must initiate, not complete, the actions requested within 15 minutes. IRO-006-EAST-1 R4 was modified to make it clear that the actions must be initiated, not completed.
- Several entities expressed concern that the TLR levels listed in IRO-006-EAST-1 still seemed to imply an obligation to adhere to the criteria as provided in the examples. In response, the SDT has removed the examples into a separate reference document that will be posted with the standard.
- Several entities suggested that there was no need to explicitly identify “responding Reliability Coordinators” in the Applicability section of IRO-006-EAST-1. Upon further reflection, the SDT agreed, and modified the applicability accordingly.
- One entity expressed concern that IRO-006-5 R1 allowed entities to simply supply a reliability reason without clearly indicating that the reason must be justified. The SDT added the word “valid” to make this clear.
- One entity identified a typographical error where Measure 1 of IRO-006-5 was missing a word. The error was corrected.
- One entity suggested improvements to the definition of Market Flow to make it clear that market flow was caused by generation internal to a market serving load internal to that same market. The definition was changed.
- Several commenters objected to the requirement to update a TLR-1 on an hourly basis. However, the requirement to re-issue TLR Level 1 every hour is already required in IRO-006-4, Attachment 1, section 1.4.4. This standard does not change this obligation.
- Some commenters suggested that the standard, by not explicitly allowing for them, could restrict the use of proxy Flowgates. The SDT clarified that this is not the intent.
- Some commenters suggested that the standard not limit the actions that can be performed concurrently with TLR as specified in IRO-0-06-EAST R1. The SDT believes that if a new method to mitigate congestion is developed other than the five actions listed, it can be included in the standard following industry review of its effectiveness in achieving the mitigation objective.
- Some entities questioned if IDC logs were acceptable evidence to show compliance with the standard. The SDT pointed out that all four of the measures clearly indicate that Logs are an acceptable form of evidence. Additionally, the measure allows for the provision of “other information.”

All comments are shown as submitted at the following site:

http://www.nerc.com/filez/standards/Reliability-Coordination-Transmission-Loading-Relief.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Jim Case	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	J. T. Wood	Southern Company	SERC	1, 3, 5
2.	Stephen Mizelle	Southern Company	SERC	1, 3, 5
3.	Shaun Anders	City of Springfield, IL (CWLP)	SERC	1, 3, 5, 9
4.	Jason Marshall	MISO	SERC	2
5.	Tim Hattaway	PowerSouth	SERC	1, 3, 5, 9
6.	Melinda Montgomery	Entergy	SERC	1, 3
7.	Sam Holeman	Duke	SERC	1, 3, 5
8.	Robert Thomasson, Jr.	Big Rivers Electric Cooperative	SERC	1, 3, 5, 9
9.	John Neagle	Associated Electric Cooperative, Inc.	SERC	1, 3, 5
10.	Mike Bryson	PJM	SERC	2
11.	John Troha	SERC Reliability corporation	SERC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Bonneville Power Administration	BPA Transmission Reliability Program	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1. Chuck Westbrook	Transmission Pre-Schedule & Real Time	WECC	1										
3.	Group	Guy Zito	Northeast Power Coordinating Council										X

Please complete the following information.

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
8.	Brian D. Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	David Kiguel	Hydro One Networks Inc.	NPCC	1
12.	Michael R. Lombardi	Northeast Utilities	NPCC	1
13.	Randy MacDonald	New Brunswick System Operator	NPCC	2
14.	Greg Mason	Dynegy Generation	NPCC	5
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
21.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
22.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10

4.	Group	Carol Gerou	MRO NERC Standards Review Subcommittee										X

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

Additional Member	Additional Organization	Region	Segment Selection
1. Chuck Lawrence	American Transmission Company	MRO	1
2. Tom Webb	WPS Corporation	MRO	3, 4, 5, 6
3. Terry Bilke	Midwest ISO Inc.	MRO	2
4. Jodi Jenson	Western Area Power Administration	MRO	1, 6
5. Ken Goldsmith	Alliant Energy	MRO	4
6. Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
7. Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8. Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9. Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
10. Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
11. Scott Nickels	Rochester Public Utilities	MRO	4
12. Terry Harbour	MidAmerican Energy Company	MRO	3, 5, 6, 1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Jason L. Marshall	Midwest ISO Stakeholders Standards Collaboration Group		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Cyrulewski	JDRJC Associates, LLC	RFC	8
2. Kirit Shah	Ameren	SERC	1
3. Doug Hohlbaugh	First Energy	RFC	1, 3, 4, 5, 6
4. Dave Folk	First Energy	RFC	1, 3, 4, 5, 6
5. Sam Ciccone	First Energy	RFC	1, 3, 4, 5, 6
6. Joe O'Brien	NIPSCO	RFC	1
7. Joe Knight	Great River Energy	MRO	1, 3, 5, 6
8. Joy Stover	Consumers Energy	RFC	3, 4, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	James T Wood	Southern Company Transmission	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. John Troha	SERC	SERC	

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
8.	Individual	James Starling	South Carolina Electric and Gas	X		X		X	X				
9.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
10.	Individual	Edward J Davis	Entergy Services	X		X		X	X				
11.	Individual	Dan Rochester	Independent Electricity System Operator		X								
12.	Individual	Martin Bauer	US Bureau of Reclamation					X					
13.	Individual	Jason Shaver	American Transmission Company	X									
14.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
15.	Individual	Joylyn Stover	Consumers Energy			X	X	X					
16.	Group	Ben Li	ISO RTO Council Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Yeung	Southwest Power Pool	SPP	2

1. The drafting team has combined IRO-006-EAST-1 R4 and R5 into a single requirement with a 15-minute target to respond to curtailment request. R5, which originally required the Responding RC to respond back to the initiating RC with a summary of actions that would be taken, was determined to be superfluous, as the first bullet would be communicated automatically through schedule changes, while the second bullet requires RC contact and approval already.

Do you agree with this change? If no, please explain your answer.

Summary Consideration: Several entities suggested that it be clear that Reliability Coordinators must 'initiate', not 'complete', the actions requested within 15 minutes. IRO-006-EAST-1 R4 was modified to make it clear that the actions must be initiated, not completed.

Organization	Yes or No	Question 1 Comment
American Electric Power		While this question refers to a "15-minute target," the language of the requirement states ". . . shall within 15 minutes of receiving the request comply with the request . . ." It is important that this difference between a mandatory 15 minute requirement and a target response of 15 minutes be resolved. The standard is unclear as to whether this phrase is requiring that the RC will have initiated one of the actions within 15 minutes or if it is requiring that these actions be completed within 15 minutes. If alternative congestion management actions (such as reconfiguration or load shedding) are employed, it may not always be possible to be completed within 15 minutes. It is important to recognize in the standard that the RC can only direct or instruct that an action be taken, not perform the action. It is the BA, subject to potential penalties for non-compliance, is the entity that will take the action to relieve the congestion.
Response: The standard has been modified to make it clear that the actions must be initiated, not completed.		
MRO NERC Standards Review Subcommittee	No	The MRO NSRS largely agrees with the change but some additional modification is needed. We are concerned that a compliance auditor could interpret the first bullet under R4 to require the RC not only to instruct actions to be taken within 15 minutes but also that the actions must be completed within 15 minutes. We believe the bullet should be changed to: "Communicate congestion management actions requested by the issuing Reliability Coordinator as follows". The language in the associated measure would then require modification as well.
Response: The standard has been modified to make it clear that the actions must be initiated, not completed.		
Consumers Energy	No	We agree with Midwest ISO comments: "We largely agree with the change but some additional modification is needed. We are concerned that a compliance auditor could interpret the first bullet under R4 to require the

Organization	Yes or No	Question 1 Comment
		RC not only to instruct actions to be taken within 15 minutes but also that the actions must be completed within 15 minutes. We believe the bullet should be changed to: "Communicate congestion management actions requested by the issuing Reliability Coordinator as follows". The language in the associated measure would then require modification as well."
Response: The standard has been modified to make it clear that the actions must be initiated, not completed.		
Southern Company Transmission	No	We are supporting comments submitted by SERC: While we do not disagree with the changes, there is an inadvertent change in meaning caused by this combination; therefore, the first bullet in R4 should be rephrased as follows: delete "Implement the communicated" and begin with, "Communicate congestion management actions ...." It is obviously impossible to complete the re-dispatch of generation within 15 minutes of notification for all curtailed schedules.
Response: The standard has been modified to make it clear that the actions must be initiated, not completed.		
Midwest ISO Stakeholders Standards Collaboration Group	No	We largely agree with the change but some additional modification is needed. We are concerned that a compliance auditor could interpret the first bullet under R4 to require the RC not only to instruct actions to be taken within 15 minutes but also that the actions must be completed within 15 minutes. We believe the bullet should be changed to: "Communicate congestion management actions requested by the issuing Reliability Coordinator as follows". The language in the associated measure would then require modification as well.
Response: The standard has been modified to make it clear that the actions must be initiated, not completed.		
Entergy Services	No	While we do not disagree with the changes, there is an inadvertent change in meaning caused by this combination; therefore, the first bullet in R4 should be rephrased as follows: delete "Implement the communicated" and begin with, "Communicate congestion management actions ...." It is obviously impossible to complete the re-dispatch of generation within 15 minutes of notification for all curtailed schedules.
Response: The standard has been modified to make it clear that the actions must be initiated, not completed.		
SERC OC Standards Review Group	No	While we do not disagree with the changes, there is an inadvertent change in meaning caused by this combination; therefore, the first bullet in R4 should be rephrased as follows: delete "Implement the communicated" and begin with, "Communicate congestion management actions ...." It is obviously impossible to complete the re-dispatch of generation within 15 minutes of notification for all curtailed schedules.

Organization	Yes or No	Question 1 Comment
Response: The standard has been modified to make it clear that the actions must be initiated, not completed.		
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Northeast Power Coordinating Council	Yes	
South Carolina Electric and Gas	Yes	
US Bureau of Reclamation	Yes	
ISO RTO Council Standards Review Committee	No	A. Requiring a 15 minute acknowledgement may not be a bad thing for TLR's involving facilities with IROLs. They could be flagged in the IDC as such; drawing attention to the criticality of the TLR. TLR's only associated with SOL should be exempt from the 15 minute acknowledgement requirement. **Response:** Transmission Operators routinely request TLRs to manage SOLs, and an SOL exceedence, while not as critical as an IROL exceedence, should still be responded to in a timely manner. A Reliability Coordinator issuing a TLR 5 could spend 10 minutes making sure the information is right, excluding tags, excluding generation, and talking it over with the Transmission Operator before ever acknowledging another RC's TLR. **Response:** The SDT believes that this is acceptable, and does not see any conflict or problem identified in this statement. If the IDC is running slow, will the RC be held accountable, or will NERC (OATI), who provides the tool, be held responsible?

Organization	Yes or No	Question 1 Comment
		As stated in the proposed Joint NERC/NAESB System Operator's Transmission Loading Relief (TLR) Reference Manual § 5.1.5, "The Reliability Coordinator shall simultaneously notify all parties affected by the invocation of a local congestion management procedure or the Interconnection-wide TLR procedure, using the notification method as specified by NERC (e.g. – the Reliability Coordinator Information System or successor)." The RCIS is currently a NERC Tool. **Response:** The SDT believes that as written, the standard applies regardless of whether entities are using RCIS or not. If the tool is broken, then the RC should be taking other actions to accomplish the tasks described in the standard. B. The Violation Severity Level (Severe VSL) for this requirement is too high. This would require the Reliability Coordinator to be more concerned about the time frame of acknowledgement to a TLR than the concern of congestion in their footprint. A TLR-1 should have the lowest VSL and no penalties. A TLR 3b or 5b should probably have a higher VSL than a 3a or 5a TLR. The "b" TLR addresses immediate, real-time issues, whereas the "a" TLR is associated with anticipated events next hour. Also, firm curtailments in a TLR-5 should have a higher VSL than a TLR-4, or lower. A TLR-6 should have the most severe VSL since it has been associated with emergencies in the past. **Response:** While this approach may have some merit for consideration if we redesign our compliance elements in the future, this does not align with our current definitions of "VRF" and "VSL." VSLs only measure the level to which the requirement is violated, not the risk associated with the requirement. To the extent we wish to apply different VRFs to each TLR level, we would need to redraft the standard to have separate requirements for each TLR level. The RC should not be held accountable at a severe level for not acknowledging a TLR when that simple acknowledgement does not guarantee the relief will be achieved. The BA has the primary role for achieving the relief, and if they do not acknowledge the curtailment then the curtailment is denied. Therefore, even if the RC acknowledges the TLR in the 15 minute time frame the BA still could miss the curtailment and not provide the relief. The penalty does not match the real time actions and consequences. **Response:** The RC, while not actually moving the generation, nonetheless has a critical responsibility to communicate the need for the movement of generation to achieve the relief requested. If the RC does not perform this task, the relief request will definitely NOT be communicated. As such, the VRF is appropriate. C. In proposed IRO-006-5, the Standard is applicable to a Balancing Authority for an Interconnection-wide TLR Procedure, and the BA is held accountable for curtailments at a severe level, but this is not the case in proposed IRO-006-East-1. Why? **Response:** IRO-006-5 applies to those entities that receive a request pursuant to an interconnection-wide

Organization	Yes or No	Question 1 Comment
		TLR procedure to curtail an Interchange Transaction that crosses an Interconnection boundary. As such, the BA is held accountable for curtailments at a severe VRF. In IRO-006-East-1, the BA is instructed to implement the curtailment but is not assigned a requirement to communicate and request the curtailments. The RCs that receive the requests from the initiating RCs are held responsible for such communications. Another example of lack of consistency can be seen in INT-005-2, which provides for a Lower VSL when a BA initiates curtailment. INT-005-2 R1.1. When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority. Violation Severity Levels, Lower VSL **Response:** The INT standards are currently in the process of being rewritten. As such, they are not used as a basis for writing this standard.
Response: Please see in-line responses.		

2. The drafting team has deleted Appendix A of IRO-006-EAST-1 and instead incorporated the table from the Appendix into requirement R2. The system conditions were relabeled as examples, a footnote was added to explain the role of the table, and a sentence was added that states "TLR levels are neither required nor expected to be issued in numerical order of level." The Drafting Team's intent with this change is to make it clear that entities must use one of the 9 levels, but that it is left solely to the discretion of the RC to determine what level is needed.

Do you believe this has been made clear? If no, please explain your answer.

Summary Consideration: Several entities expressed concern that the TLR levels still seemed to imply an obligation to adhere to the criteria as provided in the examples. In response, the SDT has removed the examples into a separate reference document that will be posted with the standard.

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Subcommittee	No	The MRO NSRS agrees the modifications improve the clarity but we feel additional changes need to be made. We are concerned that the footnote may prevent the use of proxy flowgates. We suggest that the footnote should strike "provided the Reliability Coordinator has reliability reasons to take such action" clause at the end of the second sentence. It is not needed and presumes the certification process does not work. By definition an RC that has been certified by NERC can and will only take action for reliability reasons.
Response: The language does not prevent use of proxy flowgates. Taking action on one facility to effect change on another facility is still an action taken for reliability reasons. While the SDT agrees an RC should only be taking actions for reliability reasons, we do not believe the definition alluded to ensures such motivations. Certification only verifies that entities have the "capability" to meet specific performance – certification does not "guarantee" that entities will perform in certain ways.		
Duke Energy	No	The table has been modified during the move from the Appendix into Requirement R2. The revised table descriptions of TLR levels are not as clear as they were previously. Even though they are relabeled as "examples", we think the more descriptive language from the Appendix should be included here.
Response: The information in the table has not been changed since the last posting. If this information is being compared to IRO-006-4, then the SDT removed some of that language intentionally, to make it clear the standard does not direct specific actions to be taken under specific conditions. Note that the table has now been moved into a separate reference document.		
Entergy Services	No	Tragically, by incorporating the TLR Levels as a Table in R2, the error from the last posting has been compounded. A simple table that states the set of TLR Levels and the general description of those levels is all that is needed. The "Examples of Possible System Conditions" smack of procedures and are very much a

Organization	Yes or No	Question 2 Comment
		"How" as opposed to the "What" that should be the hallmark of a good reliability standard. This will lead to mandatory compliance with the "Examples". Suggested alternative table:TLR Level Reliability Coordinator Action1 Notify Reliability Coordinators of potential System Operating Limit (SOL) or Interconnection Reliability Limit (IROL) exceedences.2 Hold Transfers at present 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.3b Curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service. 4 Reconfigure transmission system to allow Transactions using Firm Point-to-Point Transmission Service to continue.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.5b Curtail Interchange Transactions using Firm Point-to-Point Transmission Service. 6 Emergency Procedures0 TLR Concluded Delete footnote No.1. The following statement should be added to R2 directly, "The Reliability Coordinator has the discretion to choose any of these levels." Compliance is not measured on footnotes.
Response: Based on this comment and others, the SDT has removed the examples into a separate reference document that will be posted with the standard.		
SERC OC Standards Review Group	No	Tragically, by incorporating the TLR Levels as a Table in R2, the error from the last posting has been compounded. A simple table that states the set of TLR Levels and the general description of those levels is all that is needed. The "Examples of Possible System Conditions" smack of procedures and are very much a "How" as opposed to the "What" that should be the hallmark of a good reliability standard. This will lead to mandatory compliance with the "Examples". Suggested alternative table:TLR Level Reliability Coordinator Action1 Notify Reliability Coordinators of potential System Operating Limit (SOL) or Interconnection Reliability Limit (IROL) exceedences.2 Hold Transfers at present 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.3b Curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service. 4 Reconfigure transmission system to allow Transactions using Firm Point-to-Point Transmission Service to continue.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.5b Curtail Interchange Transactions using Firm Point-to-Point Transmission Service. 6 Emergency Procedures0 TLR Concluded Delete footnote No.1. The following statement should be added to R2 directly, "The Reliability Coordinator has the discretion to choose any of these levels." Compliance is not measured on footnotes.
Response: Based on this comment and others, the SDT has removed the examples into a separate reference document that will be posted with the standard.		

Organization	Yes or No	Question 2 Comment
Midwest ISO Stakeholders Standards Collaboration Group	No	We agree the modifications improve the clarity but we feel additional changes need to be made. We are concerned that the footnote may prevent the use of proxy flowgates. We suggest that the footnote should strike “provided the Reliability Coordinator has reliability reasons to take such action” clause at the end of the second sentence. It is not needed and presumes the certification process does not work. By definition an RC that has been certified by NERC can and will only take action for reliability reasons.
Response: The language does not prevent use of proxy flowgates. Taking action on one facility to effect change on another facility is still an action taken for a reliability reasons. While the SDT agrees an RC should only be taking actions for reliability reasons, we do not believe the definition alluded to ensures such motivations. Certification only verifies that entities have the “capability” to meet specific performance – certification does not “guarantee” that entities will perform in certain ways.		
Consumers Energy	No	We agree with Midwest ISO's comments: "We agree the modifications improve the clarity but we feel additional changes need to be made. We are concerned that the footnote may prevent the use of proxy flowgates. We suggest that the footnote should strike “provided the Reliability Coordinator has reliability reasons to take such action” clause at the end of the second sentence. It is not needed and presumes the certification process does not work. By definition an RC that has been certified by NERC can and will only take action for reliability reasons."
Response: The language does not prevent use of proxy flowgates. Taking action on one facility to effect change on another facility is still an action taken for a reliability reasons. While the SDT agrees an RC should only be taking actions for reliability reasons, we do not believe the definition alluded to ensures such motivations. Certification only verifies that entities have the “capability” to meet specific performance – certification does not “guarantee” that entities will perform in certain ways.		
Southern Company Transmission	No	We are supporting comments submitted by SERC: Tragically, by incorporating the TLR Levels as a Table in R2, the error from the last posting has been compounded. A simple table that states the set of TLR Levels and the general description of those levels is all that is needed. The “Examples of Possible System Conditions” smack of procedures and are very much a “How” as opposed to the “What” that should be the hallmark of a good reliability standard. This will lead to mandatory compliance with the “Examples”. Suggested alternative table: TLR Level Reliability Coordinator Action1 Notify Reliability Coordinators of potential System Operating Limit (SOL) or Interconnection Reliability Limit (IROL) exceedences.2 Hold Transfers at present 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.3b Curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service. 4 Reconfigure transmission system to allow Transactions using Firm Point-to-Point Transmission Service to continue.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

Organization	Yes or No	Question 2 Comment
		using Firm Point-to-Point.5b Curtail Interchange Transactions using Firm Point-to-Point Transmission Service. 6 Emergency Procedures0 TLR Concluded Delete footnote No.1. The following statement should be added to R2 directly, “The Reliability Coordinator has the discretion to choose any of these levels.” Compliance is not measured on footnotes.
Response: Based on this comment and others, the SDT has removed the examples into a separate reference document that will be posted with the standard.		
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Northeast Power Coordinating Council	Yes	
South Carolina Electric and Gas	Yes	
US Bureau of Reclamation	Yes	
American Electric Power	Yes	It would be clearer to use the language of the footnote in the requirement as follows:R2. When initiating the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance, and at least every clock hour after initiation up to and including the hour when the TLR level has been identified as TLR Level 0, the Reliability Coordinator shall identify: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] 2.1. The TLR level as listed below in Table 1. 2.1. 1. The listed system conditions shown in this table are intended to be alternatives for the Reliability Coordinator in determining what level of TLR to call. The Reliability Coordinator has the discretion to choose any of these levels regardless of the examples listed, provided the Reliability Coordinator has reliability reasons to take such action. TLR levels are neither required nor expected to be issued in numerical order of level. 2.2. A list of congestion management actions to be implemented based on the TLR level chosen. Please note that the text "conditions shown in this table" and "to be alternatives for" in 2.1.1. of this suggested requirement represent a change in the footnote

Organization	Yes or No	Question 2 Comment
		text.
Response: Based on this comment and others, the SDT has removed the examples into a separate reference document that will be posted with the standard.		
ISO RTO Council Standards Review Committee	No	What is the significance of the 8 hour qualifier for TLR-1 and TLR-0? Why 8 hours? Why include a time requirement?
Response: Based on this comment and others, the SDT has removed the examples into a separate reference document that will be posted with the standard.		

3. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standards.

Summary Consideration: Several entities suggested that there was no need to explicitly identify "responding Reliability Coordinators" in the Applicability section of IRO-006-EAST-1. Upon further reflection, the SDT agreed, and modified the applicability accordingly.

One entity expressed concern that IRO-006-5 R1 allowed entities to simply supply a reliability reason without clearly indicating that the reason must be justified. The SDT added the word "valid" to make this clear.

One entity identified a typographical error where Measure 1 of IRO-006-5 was missing a word. The error was corrected.

One entity suggested improvements to the definition of market flow to make it clear that market flow was caused by generation internal to a market serving load internal to that same market. The definition was changed.

Organization	Question 3 Comment
MRO NERC Standards Review Subcommittee	A. The MRO NSRS believes that the Applicability Section for IRO-006-EAST-1 needs additional clarity. We suggest the following modification. 4. Applicability 4.1 Reliability Coordinator (RC) The purpose statement already identifies that this standard is limited to only those RC in the Eastern Interconnection so repeating that in the applicability is unnecessary. **Response:** The SDT believes it is critical that the applicability of the standard be clearly documented in the applciaiblity section of the stadnard. In addition, 4.2 "Responding Reliability Coordinators" can also be deleted because the Applicability section in IRO-006-5 already covers their responsibility. Examples: (Statement) An RC in the Eastern Interconnection has to follow both IRO-006-5 and IRO-006-EAST-1 and all other RCs have to comply with IRO-006-5. (Example 1) If a RC in the Eastern Interconnection (EI) makes a request to an RC not in the Eastern Interconnection, that non EI RC still has to address the request based on R1 in IRO-006-5. (Example 2) If a non EI RC makes a request to a EI RC, the EI RC has to address the request based on R1 in IRO-006-5What these examples are demonstrating is that the Applicability Section in IRO-006-EAST-1 only has to identify Reliability Coordinators because any request made to a Reliability Coordinator in a different interconnection has to be addressed because of IRO-006-5. **Response:** The SDT concurs with your suggestion, and has changed the standard accordingly. B. The MRO NSRS is concerned that R2 requires a TLR level 1 to be reissued every hour. Currently, it is not

Organization	Question 3 Comment
	industry practice to re-issue a TLR level 1 every hour because it does not impact E-Tags. Only those levels 2 and higher should require re-issuing every hour. **Response:** The requirement to re-issue TLR Level 1 every hour is already required in IRO-006-4, Attachment 1, section 1.4.4. This standard does not change this obligation. C. The MRO NSRS continues to be concerned that the measures do not reference the IDC logs in any way as sufficient basis for demonstrating compliance. In response to our last comment on this issue, the SDT responded that industry comments agreed in a previous posting that the standards should not reference any industry specific tool. First, we can find no such record posted on the NERC web site supporting such a statement. Please identify specifically which posting and where in the posting this information is contained. Secondly, assuming that the record does exist, we question what the industry thought they were agreeing to. We believe the industry probably thought they were agreeing that the requirements should not mention the IDC which we agree with. However, including lists of IDC logs in the evidence list in the measures supports clarity in compliance which is a NERC stated goal and does not contradict what industry likely thought they were agreeing to. If the SDT does not include IDC logs in the evidence lists, then please confirm our following understanding so that there is a record of what the drafting teams intentions were that will be filed with FERC. Is it the intent of the drafting team that IDC logs mentioned in the following example would demonstrate compliance with the requirements? Consider an example where the issuing RC issues a TLR 3A (R2.1), the IDC determines curtailments through its algorithm (R2.2), the IDC communicates to all RCs (R3.1, R3.2, and R3.3), receiving RCs (including the issuing RC) acknowledge the curtailments (assuming no reliability issues), whereupon the IDC communicates tag curtailments, NNL, and market flow relief to affected BAs (R4). Are the IDC and e-tagging records clearly sufficient evidence to prove compliance with the associated requirements in parentheses above? The measures currently are not clear. We are trying to avoid a situation where the RC could not rely on the IDC for evidence and would have to make and document phone calls to every RC and every impacted BA. This would be too burdensome an outcome and would distract the System Operators from their true job ensuring and maintaining reliability. **Response:** All four of the measures clearly indicate that Logs are an acceptable form of evidence. We do not believe it is necessary to specify the kinds of logs provided. Additionally, the measure allows for the provision of "other information."
Response: Please see in-line responses.	
American Transmission Company	ATC believes that the Applicability Section for IRO-006-EAST-1 needs additional clarity. We suggest the following modification. 4. Applicability 4.1 Reliability Coordinator (RC)

Organization	Question 3 Comment
	The purpose statement already identifies that this standard is limited to only those RC in the Eastern Interconnection so repeating that in the applicability is unnecessary. **Response:** The SDT believes it is critical that the applicability of the standard be clearly documented in the applciaiblity section of the stadnard. In addition, 4.2 “Responding Reliability Coordinators” can also be deleted because the Applicability section in IRO-006-5 already covers their responsibility. Examples: (Statement) An RC in the Eastern Interconnection has to follow both IRO-006-5 and IRO-006-EAST-1 and all other RCs have to comply with IRO-006-5. (Example 1) If a RC in the Eastern Interconnection (EI) makes a request to an RC not in the Eastern Interconnection, that non EI RC still has to address the request based on R1 in IRO-006-5. (Example 2) If a non EI RC makes a request to a EI RC, the EI RC has to address the request based on R1 in IRO-006-5What these examples are demonstrating is that the Applicability Section in IRO-006-EAST-1 only has to identify Reliability Coordinators because any request made to a Reliability Coordinator in a different interconnection has to be addressed because of IRO-006-5. **Response:** The SDT concurs with your suggestion, and has changed the standard accordingly.
Response: Please see in-line responses.	
Entergy Services	Regarding R1 of IRO-006-EAST-1: Confining the available mitigation actions to the set listed in this requirement may damage reliability by preventing creative responses to system challenges. We believe that it is not possible at this time to forecast what may be available in the near future in the way of mitigation methods or techniques. Confining Requirement R1 of IRO-006-EAST-1 to a list of five currently available techniques seems like it ensures obsolescence. A sixth bullet could be added to correct this error: “Other equally effective mitigation actions”. **Response:** The standard does not prevent any RC from implementing other actions *in addition to* the five listed here, since the requirement does not prohibit other actions. However entities wishing to use an alternative method *instead of* the five listed may not do so. The SDT believes that if a new method to mitigate congestion is developed other than these five concepts, it can be included in the standard following industry review of its effectiveness in achieving the mitigation objective R2, as written, requires a TLR Level 1 to be re-issued every hour; however, current industry practice is that a TLR Level 1 is not reissued every hour. Even your table appears to indicate that a TLR level 1 only has to be re-issued every 8 hours. Please modify R2 to exclude TLR Level 1 from being re-issued every hour. **Response:** The requirement to re-issue TLR Level 1 every hour is already required in IRO-006-4, Attachment 1, section 1.4.4. This standard does not change this obligation. All measures should specifically refer to the Interchange Distribution Calculator (IDC) logs and congestion management reports, along with E-tagging logs.

Organization	Question 3 Comment
	Response: All four of the measures clearly indicate that Logs are an acceptable form of evidence. We do not believe it is necessary to specify the kinds of logs provided. Additionally, the measure allows for the provision of "other information." Entergy also would like to clarify R1 with the following changes in underline and strikeout: R1. Each Reliability Coordinator or Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a reliability reason to the Reliability Coordinator or Balancing Authority receiving the request and such request should not be implemented. .requestor that it cannot comply with the request. **Response:** The SDT does not believe the proposed changes achieve any better clarity.
Response: Please see in-line responses.	
SERC OC Standards Review Group	Regarding R1 of IRO-006-EAST-1: Confining the available mitigation actions to the set listed in this requirement may damage reliability by preventing creative responses to system challenges. We believe that it is not possible at this time to forecast what may be available in the near future in the way of mitigation methods or techniques. Confining Requirement R1 of IRO-006-EAST-1 to a list of five currently available techniques seems like it ensures obsolescence. A sixth bullet could be added to correct this error: "Other equally effective mitigation actions". **Response:** The standard does not prevent any RC from implementing other actions *in addition to* the five listed here, since the requirement does not prohibit other actions. However entities wishing to use an alternative method *instead of* the five listed may not do so. The SDT believes that if a new method to mitigate congestion is developed other than these five concepts, it can be included in the standard following industry review of its effectiveness in achieving the mitigation objective. R2, as written, requires a TLR Level 1 to be re-issued every hour; however, current industry practice is that a TLR Level 1 is not reissued every hour. Even your table appears to indicate that a TLR level 1 only has to be re-issued every 8 hours. Please modify R2 to exclude TLR Level 1 from being re-issued every hour. **Response:** The requirement to re-issue TLR Level 1 every hour is already required in IRO-006-4, Attachment 1, section 1.4.4. This standard does not change this obligation. All measures should specifically refer to the Interchange Distribution Calculator (IDC) logs and congestion management reports, along with E-tagging logs. **Response:** All four of the measures clearly indicate that Logs are an acceptable form of evidence. We do not believe

Organization	Question 3 Comment
	it is necessary to specify the kinds of logs provided. Additionally, the measure allows for the provision of "other information." "The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Response: Please see in-line responses.	
Independent Electricity System Operator	Requirement R4 requires that the RC receiving a request to implement congestion management actions shall either (a) implement them or (b) instruct implementation of alternate congestion management actions which must be agreed to by the initiating RC. Our concern is what would happen if the initiating RC does not agree? Would the RC receiving the request be expected to follow congestion management actions that in their eyes will cause a reliability concern or be ineffective, because another RC doesn't see it, or recognize it at that point in time? If not, how could this disagreement be resolved within the 15-minute window?
Response: The standard does not provide a resolution process to always result in an agreed set of actions. IRO-016-1, Requirement R1 addresses the issue of resolving operating disagreements between Reliability Coordinators. However, this lies outside of the scope of the standard.	
US Bureau of Reclamation	The VSL for R1, the text "but the entity neither complied with the request, nor provided a reliability reason that it could not comply with the request...." can easily apply to a documentation issue rather than the more serious case when the failure to comply was not appropriate as determined by the event analysis. If failure to comply was justified, then the severity level is too high.
Response: The word "valid" has been added to the standard to indicate that the failure must be justified.	
American Electric Power	To the extent that the TLR process is viewed as a reliability function rather than a business process, it would be appropriate to maintain the definition of "Reallocation" in the NERC glossary. If necessary to the term's use in this standard, the NERC definition could be up revised to read the same as the NAESB definition for "Reallocation."
Response: The SDT believes that reallocation is a business function that identifies one set of transactions for curtailment and/or reloading, rather than another set of transactions. As such, this is a business selection, not a reliability requirement, and it is covered by NAESB business practices.	
Consumers Energy	We agree with Midwest ISO's comments: "We are concerned that R2 requires a TLR level 1 to be reissued every hour. Currently, it is not industry practice to re-issue a TLR level 1 every hour because it does not impact E-Tags.

Organization	Question 3 Comment
	Only those levels 2 and higher should require re-issuing every hour. **Response:** The requirement to re-issue TLR Level 1 every hour is already required in IRO-006-4, Attachment 1, section 1.4.4. This standard does not change this obligation. We continue to be concerned that the measures do not reference the IDC logs in any way as sufficient basis for demonstrating compliance. In response to our last comment on this issue, the SDT responded that industry comments agreed in previous posting that the standards should not reference any industry specific tool. First, we can find no such record posted on the NERC web site supporting such a statement. Please identify specifically which posting and where in the posting this information is contained. Secondly, assuming that the record does exist, we question what the industry thought they were agreeing to. We believe the industry probably thought they were agreeing that the requirements should not mention the IDC which we agree with. However, including lists of IDC logs in the evidence list in the measures supports clarity in compliance which is a NERC stated goal and does not contradict what industry likely thought they were agreeing to. If the SDT does not include IDC logs in the evidence lists, then please confirm our following understand so that there is a record of what the drafting teams intentions were that will be filed with FERC. Is it the intent of the drafting team that IDC logs mentioned in the following example would demonstrate compliance with the requirements? Consider an example where the issuing RC issues a TLR 3A (R2.1), the IDC determines curtailments through its algorithm (R2.2), the IDC communicates to all RCs (R3.1, R3.2, and R3.3), receiving RCs (including the issuing RC) acknowledge the curtailments (assuming no reliability issues), whereupon the IDC communicates tag curtailments, NNL, and market flow relief to affected BAs (R4). Are the IDC and e-tagging records clearly sufficient evidence to prove compliance with the associated requirements in parentheses above? The measures currently are not clear. We are trying to avoid a situation where the RC could not rely on the IDC for evidence and would have to make and document phone calls to every RC and every impacted BA. This would be too burdensome an outcome and would distract the system operators from their true job ensuring and maintaining reliability." **Response:** All four of the measures clearly indicate that Logs are an acceptable form of evidence. We do not believe it is necessary to specify the kinds of logs provided. Additionally, the measure allows for the provision of "other information."
Response: Please see in-line responses.	
Midwest ISO Stakeholders Standards Collaboration Group	We are concerned that R2 requires a TLR level 1 to be reissued every hour. Currently, it is not industry practice to re-issue a TLR level 1 every hour because it does not impact E-Tags. Only those levels 2 and higher should require re-issuing every hour. **Response:** The requirement to re-issue TLR Level 1 every hour is already required in IRO-006-4, Attachment 1, section 1.4.4. This standard does not change this obligation.

Organization	Question 3 Comment
	We continue to be concerned that the measures do not reference the IDC logs in any way as sufficient basis for demonstrating compliance. In response to our last comment on this issue, the SDT responded that industry comments agreed in a previous posting that the standards should not reference any industry specific tool. First, we can find no such record posted on the NERC web site supporting such a statement. Please identify specifically which posting and where in the posting this information is contained. Secondly, assuming that the record does exist, we question what the industry thought they were agreeing to. We believe the industry probably thought they were agreeing that the requirements should not mention the IDC which we agree with. However, including lists of IDC logs in the evidence list in the measures supports clarity in compliance which is a NERC stated goal and does not contradict what industry likely thought they were agreeing to. If the SDT does not include IDC logs in the evidence lists, then please confirm our following understanding so that there is a record of what the drafting teams intentions were that will be filed with FERC. Is it the intent of the drafting team that IDC logs mentioned in the following example would demonstrate compliance with the requirements? Consider an example where the issuing RC issues a TLR 3A (R2.1), the IDC determines curtailments through its algorithm(R2.2), the IDC communicates to all RCs (R3.1, R3.2, and R3.3), receiving RCs (including the issuing RC) acknowledge the curtailments (assuming no reliability issues), whereupon the IDC communicates tag curtailments, NNL, and market flow relief to affected BAs (R4). Are the IDC and e-tagging records clearly sufficient evidence to prove compliance with the associated requirements in parentheses above? The measures currently are not clear. We are trying to avoid a situation where the RC could not rely on the IDC for evidence and would have to make and document phone calls to every RC and every impacted BA. This would be too burdensome an outcome and would distract the system operators from their true job ensuring and maintaining reliability. **Response:** All four of the measures clearly indicate that Logs are an acceptable form of evidence. We do not believe it is necessary to specify the kinds of logs provided. Additionally, the measure allows for the provision of “other information.”
Response: Please see in-line responses.	
Southern Company Transmission	We are supporting comments submitted by SERC: Regarding R1 of IRO-006-EAST-1: Confining the available mitigation actions to the set listed in this requirement may damage reliability by preventing creative responses to system challenges. We believe that it is not possible at this time to forecast what may be available in the near future in the way of mitigation methods or techniques. Confining Requirement R1 of IRO-006-EAST-1 to a list of five currently available techniques seems like it ensures obsolescence. A sixth bullet could be added to correct this error: “Other equally effective mitigation actions”. **Response:** The standard does not prevent any RC from implementing other actions *in addition to* the five listed here, since the requirement does not prohibit other actions. However entities wishing to use an alternative method *instead of* the five listed may not do so. The SDT believes that if a new method to mitigate congestion is developed other than these five concepts, it can be included in the standard following industry review of its effectiveness in achieving

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	the mitigation objective. R2, as written, requires a TLR Level 1 to be re-issued every hour; however, current industry practice is that a TLR Level 1 is not reissued every hour. Even your table appears to indicate that a TLR level 1 only has to be re-issued every 8 hours. Please modify R2 to exclude TLR Level 1 from being re-issued every hour. **Response:** The requirement to re-issue TLR Level 1 every hour is already required in IRO-006-4, Attachment 1, section 1.4.4. This standard does not change this obligation. All measures should specifically refer to the Interchange Distribution Calculator (IDC) logs and congestion management reports, along with E-tagging logs. **Response:** All four of the measures clearly indicate that Logs are an acceptable form of evidence. We do not believe it is necessary to specify the kinds of logs provided. Additionally, the measure allows for the provision of "other information."
Response: Please see in-line responses.	
ISO RTO Council Standards Review Committee	(1) IRO-006-East-1 R1 is redundant to IRO-009-1 R4. When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. IRO-006-East-1 R2 will list congestion management actions and TLR Level when the RC is initiating a TLR for SOL and IROLs. IRO-009-1 tells the RC how to act on an IROL. **Response:** IRO-009-1 R4 refers to actual IROL exceedances, while IRO-006-East-1 R1 is not intended to be the sole remedy used to respond to an actual IRO exceedance. IRO-006-East-1 R1 can also be used to relieve transmission constraints under conditions other than IROL exceedances. (2) In IRO-006-East-1, insert "Reliability" between "the" and "Coordinator" in the third line just after IROL's Tv. (See M1.) M1. Each Reliability Coordinator shall provide evidence (such as logs, voice recordings, or other information) that when acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's Tv, the Reliability Coordinator initiated one or more of the actions listed in R1 prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated) (R1). **Response:** Thank you for this suggestion. The error has been fixed. (3) As written, IRO-006-East-1 R2 would require the RC, upon initiation of a TLR, to re-issue the TLR each hour until it is identified as TLR Level 0. There is no need to re-issue a TLR level 1 each clock hour, as this is a notification

Organization	Question 3 Comment
	step and no action is required. A level TLR-2 and above need to be re-issued hourly to prevent or mitigate exceedances of SOLs and IROLs. **Response:** The requirement to re-issue TLR Level 1 every hour is already required in IRO-006-4, Attachment 1, section 1.4.4. This standard does not change this obligation. (4) Regarding IRO-006-East-1 R2.2, what is the intent behind "A list of congestion management actions?" Does the Reliability Coordinator who issues a TLR 5 need to list all generating units that are moved to provide NNL, or market flow? Will the RC need to list generating units that are moved to provide market relief? The RC should only have to provide the list required in R2.2 for facilities with an IROL. Facilities with only an SOL should be exempt from this requirement. Otherwise, this effort is burdensome and distracts the RC from his other duties and responsibilities. **Response:** The intent of the requirement is that it be consistent with the items identified in Part 3.3 (in other words, Interchange transactions and then relief obligations for NITS, Native Load, and Market flow, as appropriate). (5) Regarding IRO-006-East-1 M2, the VSL Level should increase as the TLR level increases. A TLR-1 should have the very lowest VSL associated with it and no penalties. A "b" TLR should probably have a higher VSL than an "a" TLR. The "b" TLR addresses immediate, real-time issues, whereas the '"a" TLR is associated with anticipated events next hour. Also, firm curtailments in a TLR-5 should have a higher VSL than a TLR-4 or lower. A TLR-6 should have the most severe VSL since it has been associated with emergencies in the past. **Response:** While this approach may have some merit for consideration if we redesign our compliance elements in the future, this does not align with our current definitions of "VRF" and "VSL." VSLs only measure the level to which the requirement is violated, not the risk associated with the requirement. To the extent we wish to apply different VRFs to each TLR level, we would need to redraft the standard to have separate requirements for each TLR level. (6) Regarding the VSLs associated with IRO-006-East-1 R3.1, specifically, what if the initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level (3.1)? This is all done automatically by the IDC and RCIS. How can the RC be held responsible for the program? How would a RC know if the other RCs in the Eastern Interconnection were notified? **Response:** The IDC Tool shows acknowledgement. If the IDC tool is not used, then the RC would be expected to verbally notify the other RCs. In FERC Order 693, paragraph 952, the Commission addresses Reliability Coordination – Transmission Loading Relief (IRO-006-3). "IRO-006-3 ensures that a reliability coordinator has a coordinated method to alleviate loadings on the transmission system if it becomes congested to avoid limit violations. IRO-006-3 establishes a detailed Transmission Loading

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	Relief (TLR) process for use in the Eastern Interconnection to alleviate loadings on the system by curtailing or changing transactions based on their priorities and according to different levels of TLR procedures. The proposed Reliability Standard includes a regional difference for reporting market flow information to the Interchange Distribution Calculator rather than tagged transaction information for the MISO and PJM areas." It also includes by reference the equivalent Interconnection-wide congestion management methods used in the WECC and ERCOT regions. Further, the proposed Joint NERC/NAESB System Operator's Transmission Loading Relief (TLR) Reference Manual includes the following: 5.1.4. Notification of TLR Procedure Implementation The Reliability Coordinator initiating the use of the TLR Procedure shall notify other Reliability Coordinators and Balancing Authorities and Transmission Operators, and must post the initiation and progress of the TLR event on the appropriate NERC web page(s). 5.1.4.1. 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. Regarding the aforementioned language from the Reference Manual, the following comment was made by MISO and MRO during the comment period for Draft 3 of TLR Standard IRO—006-5 and IRO-006-Esat-1: "Since this standard is for the Eastern Interconnection only, we ask the SDT to write the Measurements to consider presentation of IDC logs and screens as satisfactory evidence. Specifically, we ask the drafting team to modify M2 and M3 IRO-006-EAST-1 to clarify that providing the TLR history from the IDC will satisfy the evidence requirements. Since no RC ever issues a TLR without the IDC, we ask the SDT to write the requirements with consideration of the use of the IDC. For example, R3 should be clarified that the IDC can be relied upon to communicate the notifications. The RC should not be required to demonstrate that the notifications went out as appropriate or essentially that the IDC worked as designed [sic]." The SDT responded as follows: "In previous postings, commenter's have agreed that the standard should not reference any specific tool. The IDC is the name of the NERC tool that is currently used to manage the TLR process and is a way, but not necessarily the only way, to show compliance." The NERC tools allow the RC to choose a TLR Level and identify the TLR level. In the Eastern Interconnection, the IDC and RCIS are the current processes to effectuate the needed TLR. Language could be added that includes any successor tool(s). **Response:** The SDT does not see any new information here explaining why the tool needs to be referenced – only that the tool is used. All Measures include "other information". Information retrieved from the IDC and RCIS can be

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	used as satisfactory evidence. (7) IRO-006-East-1 R3.2 reads as follows: Communicate the list of congestion management actions to be implemented to 1.) All Reliability Coordinators in the Eastern Interconnection, and 2.) Those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions. Number 2 is redundant to IRO-006-5 R1 **Response:** The SDT does not believe this to be redundant. Part 3.2 require that entities be sent the list. IRO-006-5 R1 requires that entities take action upon receipt of the list. (8) The "High VSL" for IRO-006-East-1R 3 reads, in part, as follows: "The initiating Reliability Coordinator did not communicate the list of congestion management actions to one or more of the Reliability Coordinators listed in Requirement R3, Part 3.2." This again is too burdensome on the RCs, and at most should only be applied to facilities with identified IROLs. **Response:** Transmission Operators routinely request TLRs to manage SOLs, and an SOL exceedence, while not as critical as an IROL exceedance, should still be responded to in a timely manner. (9) Definitions of Terms Used in Standard The definition of "Market Flow" should be changed as follows: Market Flow: the total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of internal generation internal to the market to serve internal load internal to the market. **Response:** Thank you for your suggestion. The SDT has modified the definition per your suggestion. (10) Additional Compliance Information IRO-006-4.1…1.4.2 TLR Reports, This is a requirement of the IDC for the RC to fill out for TLR 2 and above. Why has this been removed for additional compliance? Will the Regional Entity not allow TLR Reports as evidence? **Response:** The "other information" allows the use of TLR reports. The previous Additional Compliance Information made it a requirement to fill out a TLR report. Unless this is a reliability requirement, we do not believe adding it to the compliance information will add value to the evidence that needs to be provided since this information is already covered. IRO-006-5 R1 the Balancing Authority is Applicability to the standard for Interconnection-wide TLR Procedure and

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	held accountable for curtailments at a severe level, but not in IRO-006-East, Why? But in INT-005-2 VSL level Low for the BA on curtailment? **Response:** IRO-006-5 applies to those entities that receive a request pursuant to an interconnection-wide TLR procedure to curtail an Interchange Transaction that crosses an Interconnection boundary. As such, the BA is held accountable for curtailments at a severe VRF. In IRO-006-East-1, the BA is instructed to implement the curtailment but is not assigned a requirement to communicate and request the curtailments. The RCs that receive the requests from the initiating RCs are held responsible for such communications.
Response: Please see in-line responses.	

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 the SAR and assembled a drafting team on December 5, 2006.
2. The revisions to IRO-006 to transfer business practice content to NAESB were approved as IRO-006-4 by the Board of Trustees on October 23, 2007.
3. The SDT developed a first draft for industry consideration and posted it for comments from October 30, 2008 to December 1, 2008.
4. The SDT developed a second draft for industry consideration and posted it for comments from February 19, 2009 to April 6, 2009.
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6. The SDT developed a fourth draft for industry consideration and posted it for comments from October 27, 2009 to November 30, 2009.
7. The SDT has developed this fifth and final draft for industry consideration.

Proposed Action Plan and Description of Current Draft:
This is the fifth and final draft of the proposed standard. It is being posted for 30-day Pre-Ballot Review.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
Posting for 30-day Pre-Ballot Review.	May 2010
Initial Ballot.	June 2010
Respond to comments.	July 2010
Recirculation ballot.	July 2010
Board adoption.	August 4, 2010

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.

None.

A. Introduction

1. **Title: Reliability Coordination — Transmission Loading Relief (TLR)**
2. **Number: IRO-006-5**
3. **Purpose:** To ensure coordinated action between Interconnections when implementing Interconnection-wide transmission loading relief procedures to prevent or manage potential or actual SOL and IROL exceedances to maintain reliability of the bulk electric system.
4. **Applicability:**

   4.1. Reliability Coordinator.

   4.2. Balancing Authority.
5. **Proposed Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Reliability Coordinator ~~or~~ and Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a valid reliability reason to the req~~e~~ue stor that it cannot comply with the request. [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall provide evidence (such as dated logs, voice recordings, Tag histories, and studies, in electronic or hard copy format) that, when a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure was made from another Reliability Coordinator, Balancing Authority, or Transmission Operator in that other Interconnection, it complied with the request or provided a~~n~~ valid ~~identified~~ reliability reason that it could not comply with the request (R1).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   Regional Entity.

   ~~**1.2.Compliance Monitoring Period and Reset Time Frame**~~

~~Not applicable.~~

1.2. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.3. Data Retention

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

- The Reliability Coordinator and Balancing Authority shall maintain evidence to show compliance with R1 for the most recent twelve calendar months plus the current month.
- If a Reliability Coordinator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

~~1.4.Compliance Monitoring and Enforcement Processes:~~

~~The following processes may be used:~~

~~-Compliance Audits~~

~~-Self-Certifications~~

~~-Spot Checking~~

~~-Compliance Violation Investigations~~

~~-Self-Reporting~~

~~-Complaints~~

~~1.5.~~1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				The responsible entity received a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority, or Transmission Operator, but the entity neither complied with the request, nor provided a valid reliability reason ~~that~~ why it could not comply with the request.

E. Variances

None.

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
4	October 23, 2007	Completed NERC/NAESB split	Revision
5		Removed Attachment 1 and made into a new standard, eliminated unnecessary requirements.	Revision

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~~**Reallocation:** The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.~~ (To be retired.)

Market Flow: the total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of ~~internal~~ generation internal to the market to serve Load internal to the market ~~load~~.

A. Introduction

1. **Title: Transmission Loading Relief Procedure for the Eastern Interconnection**

2. **Number:** IRO-006-EAST-1

3. **Purpose:** To provide an Interconnection-wide transmission loading relief procedure (TLR) for the Eastern Interconnection that can be used to prevent and/or mitigate potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).

4. **Applicability:**

   ~~4.1.Initiating~~ Reliability Coordinators in the Eastern Interconnection.

   ~~4.2.~~**4.1.** ~~Responding Reliability Coordinators~~

5. **Proposed Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_V, each Reliability Coordinator shall initiate, prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated), one or more of the following actions: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

- Inter-area redispatch
- Intra-area redispatch of generation
- Reconfiguration of the transmission system
- Voluntary load reductions (e.g., Demand-side Management)
- Involuntary load reductions

R2. In order to ensure operating entities are provided with information needed to maintain an awareness of changes to the Transmission System, ~~W~~when initiating the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance, and at least every clock hour after initiation up to and including the hour when the TLR level has been identified as TLR Level 0, the Reliability Coordinator shall identify: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

2.1. A list of congestion management actions to be implemented, and ~~The TLR level as listed below in Table 1, and~~

2.2. ~~A list of congestion management actions to be implemented based on the TLR level chosen.~~One of the following TLR levels: TLR-1, TLR-2, TLR-3A, TLR-3B, TLR-4, TLR-5A, TLR-5B, TLR-6, TLR-0

~~TABLE 1—TLR LEVELS~~[1]

~~Level~~	~~Examples of Possible System Conditions~~
~~TLR-1~~	• ~~At least one Transmission Facility is expected to approach or exceed its SOL or IROL within 8 hours.~~
~~TLR-2~~	• ~~At least one Transmission Facility is approaching or is at its SOL or IROL.~~ o ~~Analysis shows that holding new and increasing non-firm Interchange Transactions and energy flows for the next hour can prevent exceeding this SOL or IROL.~~
~~TLR-3a~~	• ~~At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour.~~ o ~~Analysis shows that full or partial curtailment or reallocation~~[2] ~~of non-firm Interchange Transactions and energy flows can prevent exceeding this SOL and IROL.~~
~~TLR-3b~~	• ~~At least one Transmission Facility is exceeding its SOL or IROL, or~~ • ~~At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour.~~ o ~~Analysis shows that full or partial curtailment or reallocation~~[3] ~~of non-firm Interchange Transactions and energy flows can prevent exceeding this SOL or IROLs.~~
~~TLR-4~~	• ~~At least one Transmission Facility is expected to exceed its SOL or IROL.~~ o ~~Analysis shows that full curtailment of non-firm Interchange Transactions and energy flows, or reconfiguration of the transmission system can prevent exceeding this SOL or IROL.~~
~~TLR-5a~~	• ~~At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour.~~ o ~~Analysis shows that the following actions can prevent exceeding the SOL or IROL:~~ • ~~Full curtailment non-firm Interchange Transactions and energy flows, and~~ • ~~Reconfiguration of the transmission system, if possible, and~~ • ~~Full or partial curtailment or reallocation~~[4] ~~of firm Interchange Transactions and energy flows.~~
~~TLR-5b~~	• ~~At least one Transmission Facility is exceeding its SOL or IROL, or~~ • ~~At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour.~~ o ~~Analysis shows that the following actions can prevent exceeding the SOL or IROL:~~ ▪ ~~Full curtailment of non-firm Interchange Transactions and energy flows, and~~ ▪ ~~Reconfiguration of the transmission system, if possible, and~~ ▪ ~~Full or partial curtailment or reallocation~~[5] ~~of firm Interchange Transactions and energy flows.~~
~~TLR-6~~	• ~~At least one Transmission Facility is exceeding its SOL or IROL, or~~ • ~~At least one Transmission Facility is expected to exceed its SOL or IROL upon the removal from service of a generating unit or another transmission facility.~~
~~TLR-0~~	• ~~No transmission facilities are expected to approach or exceed their SOL or IROL within 8 hours, and the ICM procedure may be terminated~~

R3. Upon the identification of the TLR level and a list of congestion management actions to be implemented ~~based on the TLR level chosen~~, the Reliability Coordinator initiating this TLR procedure shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

~~[1] The listed system conditions examples are intended to assist the Reliability Coordinator in determining what level of TLR to call. The Reliability Coordinator has the discretion to choose any of these levels regardless of the examples listed, provided the Reliability Coordinator has reliability reasons to take such action. TLR levels are neither required nor expected to be issued in numerical order of level.~~

~~[2,3,4,5] "Reallocation" is a term defined within the NAESB TLR standards.~~

3.1. Notify all Reliability Coordinators in the Eastern Interconnection of the identified TLR level

3.2. Communicate the list of congestion management actions to be implemented to 1.) all Reliability Coordinators in the Eastern Interconnection, and 2.) those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions.

3.3. Request that the congestion management actions identified in Requirement R2, Part 2.2 be implemented by:

1.) Each Reliability Coordinator associated with a Sink Balancing Authority for which Interchange Transactions are to be curtailed,

2.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which Network Integration Transmission Service or Native Load is to be curtailed, and

3.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which its Market Flow is to be curtailed.

R4. Each Reliability Coordinator that receives a request as described in Requirement R3, Part 3.3. shall, within 15 minutes of receiving the request, implement the communicated congestion management actions requested by the issuing Reliability Coordinator as follows~~comply with the request by taking one or both of the following sets of actions~~: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

- ~~Implement the communicated congestion management actions requested by the issuing Reliability Coordinator as follows:~~
- Instruct its Balancing Authorities to implement the Interchange Transaction schedule change requests.
- Instruct its Balancing Authorities to implement the Network Integration Transmission Service and Native Load schedule changes for which the Balancing Authorities are responsible.
- Instruct its Balancing Authorities to implement the Market Flow schedule changes for which the Balancing Authorities are responsible
- If assessment determines that one or more of the congestion management actions communicated in Requirement R3, Part 3.3 will result in a reliability concern or will be ineffective, ~~Instruct implementation~~the Reliability Coordinator may replace those specific actions with ~~of~~ alternate congestion management actions~~to those communicated in R3~~, provided that:
  - ~~Assessment determines that some or all of the congestion management actions communicated in Requirement R3, Part 3.3 will result in a reliability concern or will be ineffective, and~~
  - The alternate congestion management actions have been agreed to by the initiating Reliability Coordinator, and
  - Assessment shows that the alternate congestion management actions will not adversely affect reliability.

C. Measures

M1. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that when acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_v, the Reliability Coordinator initiated one or more of the actions listed in R1 prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated)(R1).

M2. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that at the time it initiated the Eastern Interconnection TLR procedure, and at least every clock hour after initiation up to and including the hour when the TLR level was identified as TLR Level 0, the Reliability Coordinator identified both the TLR Level and a list of congestion management actions to be implemented ~~based on the TLR level chosen~~ (R2).

M3. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that after it identified a TLR level and a list of congestion management actions to take, it 1.) notified all Reliability Coordinators in the Eastern Interconnection of the TLR Level, 2.) communicated the list of actions to all Reliability Coordinators in the Eastern Interconnection and those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions, and 3.) requested the Reliability Coordinators identified in Requirement R3 Part 3.2 to implement the congestion management actions identified in Requirement R2 Part 2.2 (R3).

M4. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that within fifteen minutes of the receipt of a request as described in R3, the Reliability Coordinator complied with the request by either 1.) ~~taking one or both of the following: 1.)~~ implement~~ed~~ing the communicated congestion management actions requested by the issuing Reliability Coordinator, or 2.) implementing some of the communicated congestion management actions requested by the issuing Reliability Coordinator, and replacing the remainder with ~~implemented~~ alternate congestion management actions ~~based on~~ if assessment ~~which~~ showed that some or all of the congestion management actions communicated in R3 would have resulted in a reliability concern or would have been ineffective, the alternate congestion management actions were agreed to by the initiating Reliability Coordinator, and assessment showed that the alternate congestion management actions would not adversely affect reliability (R4).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

~~**1.2. Compliance Monitoring Period and Reset Time Frame**~~

~~**Not applicable.**~~

1.2. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.3. Data Retention

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

- The Reliability Coordinator shall maintain evidence to show compliance with R1, R2, R3, and R4 for the past 12 months plus the current month.
- If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

~~**1.4. Compliance Monitoring and Enforcement Processes:**~~

~~**1. The following processes may be used:**~~

- ~~**Compliance Audits**~~
- ~~**Self-Certifications**~~
- ~~**Spot Checking**~~
- ~~**Compliance Violation Investigations**~~
- ~~**Self-Reporting**~~
- ~~**Complaints**~~

~~**1.5.**~~**1.4. Additional Compliance Information**

None.

3. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_v, the Reliability Coordinator did not initiate one or more of the actions listed under R1 prior to or in conjunction with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated).
R2	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take ~~based on the TLR level chosen~~ for one clock hour during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take ~~based on the TLR level chosen~~ for two clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.~~,~~	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take ~~based on the TLR level chosen~~ for three clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take ~~based on the TLR level chosen~~ for four or more clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.
R3	The initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level (3.1).	N/A	The initiating Reliability Coordinator did not communicate the list of congestion management actions to one or more of the Reliability Coordinators listed in Requirement R3, Part 3.2.	The initiating Reliability Coordinator requested none of the Reliability Coordinators identified in Requirement R3, Part 3.3 to implement the identified congestion management actions.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The initiating Reliability Coordinator requested some, but not all, of the Reliability Coordinators identified in Requirement R3, Part 3.3 to implement the identified congestion management actions.	
R4				The responding Reliability Coordinator did not ~~take one or both of the following~~, ~~actions~~ within 15 minutes of receiving a request~~:~~ ~~1.) I~~, either 1.) implement~~ed~~ all the requested congestion management actions, or 2.) implement some of the requested congestion management actions and replace the remainder with ~~.~~ ~~2.) Implemented~~ alternate congestion management actions, provided that: ~~based on~~ assessment ~~which~~ showed that ~~some or all of the actions communicated in Requirement R3 Part 3.3~~the actions replaced would have resulted in a reliability concern or would have been ineffective, ~~and that~~ the alternate congestion management actions were agreed to by the initiating Reliability Coordinator, and

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment determined that the alternate congestion management actions would not adversely affect reliability.

E. Variances

None.

F. Associated Documents

TLR Level Reference Document

Revision History

Version	Date	Action	Tracking
1		Creation of new standard, incorporating concepts from IRO-006-4 Attachment; elimination of Regional Differences, as the standard allows the use of Market Flow	New

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan for Standard IRO-006-5 (Reliability Coordination — Transmission Loading Relief (TLR)) and IRO-006-EI-1 (Loading Relief Procedure for the Eastern Interconnection)

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved or in progress, that must be implemented before ~~this~~ these standards can be implemented.

Modified Definitions

The definition of "Reallocation" should be removed from the Glossary when IRO-006-5 and IRO-006-EI-1 become effective. The drafting team has verified that the term, "Reallocation" is not used in any other approved standard.

Modified Standards

IRO-006-4, and associated Attachment 1, should be retired when IRO-006-5 and IRO-006-EI-1 become effective.

The Regional Differences within IRO-006-4 should be retired when IRO-006-5 and IRO-006-EI-1 become effective.

Compliance with Standards

Once the standards become effective, the responsible entities identified in the applicability section of the standards must comply with the requirements. These include:

- Reliability Coordinators
- Balancing Authorities

Proposed Effective Date

The standards will become effective on the first day of the first calendar quarter after the date the standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standards becomes effective on the first day of the first calendar quarter after the date the standards are approved by the NERC Board of Trustees.

Justification for VRFs and VSLs in IRO-006-5 and IRO-006-EAST-1

This document provides the justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), identifying how each proposed VRF and VSL meets NERC's criteria and FERC's Guidelines. NERC's criteria for setting VRFs and VSLs; FERC's five guidelines (G1–G5) for approving VRFs; and FERC's four guidelines (G1-G4) for setting VSLs are provided at the end of this document.

IRO-006-5 VRF and VSL Justifications		
R1	Proposed VRF	High
	NERC VRF Discussion	An entity in another interconnection that does not curtail as requested will leave their interconnection unbalanced, which could contribute to BES instability.
	FERC VRF G1 Discussion	The requirement is related to the use of Transmission Loading Relief, but is not related to the appropriateness of using TLR. As such, the VRF is not required to be High.
	FERC VRF G2 Discussion	This standard does not utilize sub-requirements, but instead uses parts. Additionally, the standard has only one requirement. As such, G2 does not apply.
	FERC VRF G3 Discussion	This VRF is consistent with that of IRO-001 R8, which establishes the responsibility of entities to respond to the directives of Reliability Coordinators.
	FERC VRF G4 Discussion	An entity in another interconnection that does not curtail as requested will leave their interconnection unbalanced, which could contribute to BES instability.
	FERC VRF G5 Discussion	This requirement does not co-mingle reliability objectives.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The responsible entity received a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority, or Transmission Operator, but the entity neither complied with the request, nor provided a valid reliability reason that it could not comply with the request.
	FERC VSL G1 Discussion	No longer applicable given significant changes in standard structure.
	FERC VSL G2 Discussion	The VSL is written as a pass/fail VSL, and it has been set at the "Severe" level, meeting guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
	FERC VSL G3 Discussion	The VSL aligns with the language of the requirement, and does not add to nor take away from it.

	FERC VSL G4 Discussion	The VSL is based on a single violation of the requirement.
IRO-006-EAST-1 VSL and VRF Justifications		
R1	Proposed VRF	High
	NERC VRF Discussion	An entity that, when responding to an IROL, only implements the TLR procedure alone and does not take other action prior to or concurrently with the TLR procedure has placed the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G1 Discussion	The requirement is related to the use of Transmission Loading Relief, and is related to the appropriateness of using TLR. As such, the VRF is required to be High.
	FERC VRF G2 Discussion	This standard does not utilize sub-requirements, but instead uses parts. As such, G2 does not apply. However, the VRFs for this requirement are consistent with others in the standard with regard to relative risk.
	FERC VRF G3 Discussion	The requirement is consistent with IRO-009 R4. As this requirement addresses the manner in which entities respond to actual IROL exceedances, it is appropriate that this requirement share that same VRF of High.
	FERC VRF G4 Discussion	An entity that, when responding to an IROL, only implements the TLR procedure alone and does not take other action prior to or concurrently with the TLR procedure has placed the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	This requirement does not co-mingle reliability objectives.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's Tv, the Reliability Coordinator did not initiate one or more of the actions listed under R1 prior to or in conjunction with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated).
	FERC VSL G1 Discussion	No longer applicable given significant changes in standard structure.
	FERC VSL G2 Discussion	The VSL is written as a pass/fail VSL, and it has been set at the "Severe" level, meeting guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
	FERC VSL G3 Discussion	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
	FERC VSL G4 Discussion	The VSL is based on a single violation of the requirement.

R2	Proposed VRF	Medium
	NERC VRF Discussion	An entity that does not continually identify TLR level and actions to take on at least an hourly basis may have a negative effect on the reliability of the BES by reducing coordination, but that action alone is unlikely to lead to bulk electric system instability, separation, or cascading failures.
	FERC VRF G1 Discussion	The requirement is related to the use of Transmission Loading Relief, but is not related to the appropriateness of using TLR. As such, the VRF is not required to be High.
	FERC VRF G2 Discussion	This standard does not utilize sub-requirements, but instead uses parts. As such, G2 does not apply. However, the VRFs for this requirement are consistent with others in the standard with regard to relative risk.
	FERC VRF G3 Discussion	IRO-005-2 R7 indicates that the dissemination of information from the RC should be considered as having a "High" risk factor. However, IRO-005 R7 does not specify the type of information to be disseminated. Absent that specificity, it is unclear whether or not all information is of high risk, or if only some is of high risk. Since FERC VRF Guideline 5 requires that entities err toward the more conservative, it would appear that IRO-005 R7 assumes that at least one piece of information to disseminate is of a critical nature. However, when discussing the specifics, the SDT believes that the non-dissemination of the information required in IRO-006 R2 alone is unlikely to lead to bulk electric system instability, separation, or cascading failures. As such, the team believes the VRF is appropriate. Additionally, the Medium VRF is consistent with IRO-015 R1.
	FERC VRF G4 Discussion	An entity that does not continually identify TLR level and actions to take on at least an hourly basis may have a negative effect on the reliability of the BES by reducing coordination, but that action alone is unlikely to lead to bulk electric system instability, separation, or cascading failures.
	FERC VRF G5 Discussion	This requirement does not co-mingle reliability objectives.
	Proposed Lower VSL	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take based on the TLR level chosen for one clock hour during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.
	Proposed Moderate VSL	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take based on the TLR level chosen for two clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0
	Proposed High VSL	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take based on the TLR level chosen for three clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.
	Proposed Severe VSL	The Reliability Coordinator initiating the Eastern Interconnection TLR

		procedure missed identifying the TLR Level and/or a list of congestion management actions to take based on the TLR level chosen for four or more clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.
	FERC VSL G1 Discussion	No longer applicable given significant changes in standard structure.
	FERC VSL G2 Discussion	The VSL is written as a graded VSL, meeting guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
	FERC VSL G3 Discussion	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
	FERC VSL G4 Discussion	The Requirement mandates continuous hourly identification of TLR level and actions, and the VSL is based on the continuity of those actions. The VSL is correctly based on multiple violations.

R3	Proposed VRF	Medium
	NERC VRF Discussion	An entity that does not notify entities or request the actions as described in the requirement may have a negative effect on the reliability of the BES by reducing coordination, but that action alone is unlikely to lead to bulk electric system instability, separation, or cascading failures.
	FERC VRF G1 Discussion	The requirement is related to the use of Transmission Loading Relief, but is not related to the appropriateness of using TLR. As such, the VRF is not required to be High.
	FERC VRF G2 Discussion	This standard does not utilize sub-requirements, but instead uses parts. As such, G2 does not apply. However, the VRFs for this requirement are consistent with others in the standard with regard to relative risk.
	FERC VRF G3 Discussion	IRO-005-2 R7 indicates that the dissemination of information from the RC should be considered as having a “High” risk factor. However, IRO-005 R7 does not specify the type of information to be disseminated. Absent that specificity, it is unclear whether or not all information is of high risk, or if only some is of high risk. Since FERC VRF Guideline 5 requires that entities err toward the more conservative, it would appear that IRO-005 R7 assumes that at least one piece of information to disseminate is of a critical nature. However, when discussing the specifics, the SDT believes that the failure to notify or make specific requests from the TLR procedure alone is unlikely to lead to bulk electric system instability, separation, or cascading failures. As such, the team believes the VRF is appropriate.
	FERC VRF G4 Discussion	An entity that does not notify entities or request the actions as described in the requirement may have a negative effect on the reliability of the BES by reducing coordination, but that action alone is unlikely to lead to bulk electric system instability, separation, or cascading failures.
	FERC VRF G5 Discussion	This requirement co-mingles reliability objectives, but does not reflect the lower risk level associated with the less important objective.
	Proposed Lower VSL	The initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR

		Level (3.1).
	Proposed Moderate VSL	N/A
	Proposed High VSL	The initiating Reliability Coordinator did not communicate the list of congestion management actions to one or more of the Reliability Coordinators listed in Requirement R3 Part 3.2. OR The initiating Reliability Coordinator requested some, but not all, of the Reliability Coordinators identified in Requirement R3 Part 3.3 to implement the identified congestion management actions.
	Proposed Severe VSL	The initiating Reliability Coordinator requested none of the Reliability Coordinators identified in Requirement R3 Part 3.3 to implement the identified congestion management actions.
	FERC VSL G1 Discussion	No longer applicable given significant changes in standard structure.
	FERC VSL G2 Discussion	The VSL is written as a graded VSL, meeting guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
	FERC VSL G3 Discussion	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
	FERC VSL G4 Discussion	The VSL is based on a single violation of the requirement.

R4	Proposed VRF	High
	NERC VRF Discussion	An entity that, when responding to a request to take action as part of the TLR procedure, does not take such action (or alternative action as described in the requirement) could be causing or contributing to bulk electric system instability, separation, or a cascading sequence of failures
	FERC VRF G1 Discussion	The requirement is related to the use of Transmission Loading Relief, but is not related to the appropriateness of using TLR. As such, the VRF is not required to be High.
	FERC VRF G2 Discussion	This standard does not utilize sub-requirements, but instead uses parts. As such, G2 does not apply. However, the VRFs for this requirement are consistent with others in the standard with regard to relative risk.
	FERC VRF G3 Discussion	This VRF is consistent with that of IRO-001 R8, which establishes the responsibility of entities to respond to the directives of Reliability Coordinators.
	FERC VRF G4 Discussion	An entity that, when responding to a request to take action as part of the TLR procedure, does not take such action (or alternative action as described in the requirement) could be causing or contributing to bulk electric system instability, separation, or a cascading sequence of failures
	FERC VRF G5 Discussion	This requirement does not co-mingle reliability objectives.

	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The responding Reliability Coordinator did not initiate one or both of the following actions within 15 minutes of receiving a request: 1.) Implemented the requested congestion management actions. 2.) Implemented alternate congestion management actions based on assessment which showed that some or all of the actions communicated in Requirement R3 Part 3.3 would have resulted in a reliability concern or would have been ineffective, and that the alternate congestion management actions were agreed to by the initiating Reliability Coordinator and assessment determined that the alternate congestion management actions would not adversely affect reliability.
	FERC VSL G1 Discussion	No longer applicable given significant changes in standard structure.
	FERC VSL G2 Discussion	The VSL is written as a pass/fail VSL, and it has been set at the “Severe” level, meeting guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
	FERC VSL G3 Discussion	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
	FERC VSL G4 Discussion	The VSL is based on a single violation of the requirement.

NERC's VRF Criteria:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC's VRF Guidelines:

VRF G1 — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. From footnote 15 of the May 18, 2007 Order, FERC's list of critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System includes:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

VRF G2 — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

VRF G3 — Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

VRF G4 — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

VRF G5 — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC's Criteria for VSLs:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC's VSL Guidelines:
VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance (Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.)

VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties (A violation of a "binary" type requirement must be a "Severe" VSL. Avoid using ambiguous terms such as "minor" and "significant" to describe noncompliant performance.)

VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement (VSLs should not expand on what is required in the requirement.)

VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations (. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.)

Ballot Results	
Ballot Name:	Project 2006-08 - Reliability Coordination - Transmission Loading Relief _in
Ballot Period:	6/23/2010 - 7/6/2010
Ballot Type:	Initial
Total # Votes:	215
Total Ballot Pool:	247
Quorum:	**87.04 % The Quorum has been reached**
Weighted Segment Vote:	84.98 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

			Affirmative		Negative		Abstain	
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	# Votes	No Vote
1 - Segment 1.	69	1	43	0.878	6	0.122	12	8
2 - Segment 2.	10	0.9	7	0.7	2	0.2	0	1
3 - Segment 3.	56	1	32	0.842	6	0.158	9	9
4 - Segment 4.	15	1	13	0.867	2	0.133	0	0
5 - Segment 5.	43	1	24	0.828	5	0.172	9	5
6 - Segment 6.	34	1	17	0.773	5	0.227	6	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.5	4	0.4	1	0.1	1	0
9 - Segment 9.	6	0.5	5	0.5	0	0	0	1
10 - Segment 10.	8	0.5	5	0.5	0	0	1	2
Totals	**247**	**7.4**	**150**	**6.288**	**27**	**1.112**	**38**	**32**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	Avista Corp.	Scott Kinney	Abstain	
1	BC Transmission Corporation	Gordon Rawlings	Abstain	
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Abstain	
1	Central Maine Power Company	Brian Conroy	Affirmative	

1	City of Vero Beach	Randall McCamish	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	John K Loftis	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	View
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett		
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg		
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	View
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lake Worth Utilities	Walt Gill	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Saurabh Saksena	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Negative	View
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Mark Sampson	Abstain	
1	Portland General Electric Co.	Frank F. Afranji	Abstain	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Negative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Abstain	
1	San Diego Gas & Electric	Linda Brown	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Abstain	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry Akens		
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Affirmative	View
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	California ISO	Timothy VanBlaricom	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	View

2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool	Charles H Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock		
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Abstain	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Negative	View
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone		
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Negative	
3	Lincoln Electric System	Bruce Merrill	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PacifiCorp	John Apperson	Abstain	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Abstain	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Wisconsin Electric Power Marketing	James R. Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	

4	Consumers Energy	David Frank Ronk	Negative	View
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Abstain	
5	City of Tallahassee	Alan Gale	Affirmative	
5	Conectiv Energy Supply, Inc.	Kara Dundas		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy	James B Lewis	Negative	View
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Electric Power Supply Association	Jack R. Cashin	Affirmative	View
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Cynthia E Sulzer		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Louisville Gas and Electric Co.	Charlie Martin	Negative	View
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	Nebraska Public Power District	Jon Sunneberg	Abstain	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Otter Tail Power Company	Ward Uggerud	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Power LLC	David Murray	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Abstain	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Negative	View
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Barry Green Consulting Inc.	Barry Green	Affirmative	View
6	Bonneville Power Administration	Brenda S. Anderson	Abstain	
6	Cleco Power LLC	Matthew D Cripps	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S Slade	Abstain	
6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery		

6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan R. Johnson	Affirmative	
6	Omaha Public Power District	David Ried	Negative	
6	Progress Energy	James Eckelkamp		
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Salt River Project	Mike Hummel	Abstain	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Negative	View
8	Power Energy Group LLC	Peggy Abbadini	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	View
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Project 2006-08 — Reliability Coordination — Transmission Loading Relief
Date of Initial Ballot: June 23, 2010 through July 6, 2010

Summary Consideration:

Entities suggested minor clarifications, corrections, and language changes that were accepted by the SDT.

- Some entities had concerns with the potential subjectivity of the requirement in IRO-006-5 Requirement R1 for a "valid" reason. The SDT agreed with their concerns, and eliminated the word "valid."

- Several entities objected to the need to reissue TLR-1 each hour specified in IRO-006-EAST-1 Requirement R2. Upon further review of the current standard, as well as the current implementation of the Interchange Distribution Calculator (IDC), it was determined that such updates are not required for TLR-1. The phrase "with the exception of TLR-1, where an hourly update is not required" was added to the requirement.

- Some entities expressed concern that the list of TLR levels and conditions, which was moved into a supporting document, would be more appropriately included as an attachment or a requirement. Since the information does not actually represent any specific required action, the SDT believes it is more appropriate to maintain this information in a separate document. The SDT did add a footnote to assist entities in locating the information.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Douglas E. Hils	Duke Energy Carolina	1	Affirmative	"For clarity, we recommend replacing the phrase "ICM procedure" with the phrase "Interconnection wide transmission loading relief procedure" in the Implementation Guideline TLR Levels Table."
Response: Thank you. The change has been made.				

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Kim Warren	Independent Electricity System Operator	2	Affirmative	IRO-006-5, Requirement R1 We don’t see the need for the word “valid” introduced in this 5th draft of IRO-006-5. It begs the question “Who will judge the validity of a reliability reason advanced by the RC or BA receiving the request, and not complying with it?” We don’t believe the responsible entities would be “irresponsible” by offering “invalid” reasons. They will make a judgment at the moment the request is made, based on the information they have, studies they conduct and experience of their operators. The reliability reason they give should be complete enough (within the time and information constraints) to substantiate their decision. It is also open to speculation whether an auditor would come after the fact and assess whether or not the reasons advanced for a particular event in the past were valid. The requirement is for a “reason” which should be documented and which by definition should have some solid basis. One would not expect an entity to put forward a frivolous reason. We recommend removing “valid”. **Response**: The SDT has eliminated to the use of the word “valid” as proposed. IRO-006-EAST-1, Requirement R2, Part 2.2 We believe there should be a URL or reference to the TLR Level Reference Document indicated in Section F of the standard. We propose inserting the following text immediately before the colon: “as defined in TLR Level Reference Document found at…” **Response**: Thank you. The SDT has clarified the reference in Section F, and added a footnote to Requirement R2, Part 2.2. However, we do not believe is appropriate to make direct reference to the document in R2, as this could be interpreted as incorporation of the reference into the requirement and then make the guideline mandatory and enforceable. IRO-006-EAST-1, Requirement R3, Part 3.3 We believe the reference should be to Requirement R2, Part 2.1 and not Part 2.2. The final line of M3 should also reflect this change. **Response**: Thank you. The correction has been made. IRO-006-EAST-1, Requirement R4 In R4 “communicated” is redundant and should be removed. The 4th bullet of R4 is an implied requirement to carry out an assessment and it is not clear that the RC is required to do this. For clarity we recommend making

Voter	Entity	Segment	Vote	Comment
				this requirement explicit. We propose the following alternative wording: Assess the congestion management actions communicated in Requirement R3, Part 3.3 to determine which if any will result in a reliability concern or will be ineffective and replace those specific actions with alternate congestion management actions, provided that: **Response**: Regarding the elimination of the redundant word "communicated," the word has been removed. Regarding the implied requirement to carry out an assessment: this standard does not require the assessment, but if the RC in its normal course of duties performs such an assessment and discovers a concern, the fourth bullet makes it clear that it may use that assessment as justification for alternate actions.
Response: Please see in-line responses.				
Kevin Querry	FirstEnergy Solutions	3	Affirmative	No Comment
Response: Thank you for your affirmative response.				
Michael Gammon	Kansas City Power & Light Co.	1	Affirmative	Per IRO-EAST-1 R2, TLR 1 will have to be reissued every clock hour. Since there is no operational action required for TLR 1, this serves no reliability purpose and only provides the market with updates on the TLR 1 status. However because M2 does not distinguish whether the issuances were made for any particular TLR level, a reliability penalty can be applied for not reissuing a TLR1 for a market benefit. Although KCPL supports the changes to the IRO standards and understand benefits to the market of some of these changes, we see a disconnect from enforcing a requirement for a market benefit with a reliability sanction. In addition, transmission customers do not request hourly updates to TLR 1 status as may be the case in other regions where such information may be crucial. We believe the VSLs should be modified to reflect that only reissuance of TLR 2 and higher will be considered for compliance with IRO-EAST-1 R2.
Response: Upon further review of the current standard, as well as the current implementation of the IDC, it was determined that such updates are not required for TLR-1. The phrase "with the exception of TLR-1, where an hourly update is not required" was added to the requirement.				
Kent Saathoff	Electric Reliability Council of Texas, Inc.	10	Affirmative	The addition of the word "valid" in regard to reliability reasons is not necessary and highly subject to individual and conflicting interpretations. It should be deleted.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has eliminated to the use of the word "valid" as proposed.				
Jason L. Murray	Alberta Electric System Operator	2	Affirmative	The term "valid reliability reason" does not clarify the standard, unless a list of valid reasons is developed.
Response: The SDT has eliminated to the use of the word "valid" as proposed.				
Barry Green	Barry Green Consulting Inc.	6	Affirmative	The TLR process is of great concern to all Registered Entities. I, on behalf of the Electric Power Supply Association and its members am closely monitoring developments in the TLR process at FERC as well as changes to these standards, changes to the NAESB Business Practices and IDC changes being specified and implemented by the ORS and IDCWG. On-going coordination of the work in these various forums is critical. Although generally supportive of these standards, there is one question with respect to the deletion of Table 1 which provides "Examples of Possible System Conditions" previously contained in requirement R2.2 of IRO-006-EAST-1. I understand that the Table is now proposed to be included with the Implementation Guideline for RCs in the Eastern Interconnection. However, this information is to be used by RCs to identify (requirement R2.2) the appropriate TLR level and to notify (requirement R3.1) all RCs in the Eastern Interconnection of the identified level. And furthermore, this information will impact many registered entities conducting business in areas where TLRs have been called. Therefore I believe that it would be more appropriate that the Table either be part of the standard or an appendix to it. Doing so would insure that all registered entities impacted by TLRs would have ready access to this information. I recognize the need for flexibility for RCs to use discretion in selecting the appropriate TLR level based on the circumstances they are facing which may not precisely match any pre-identified criteria. However, the examples contained in the Table are still a useful reference for all, not just the RCs.
Response: The SDT does not believe that including the examples in a supporting document will preclude them from use by entities other than RCs. Not including this information in the standard or as an appendix clearly draws the line between what is required and what is not, and calling specific TLR levels based on specific conditions is not part of the requirement. The SDT will ask the SC for authorization to post the reference document with a link to the associated standard so that the information will be easy to locate.				
Jack R. Cashin	Electric Power Supply Association	5	Affirmative	The Transmission Loading Relief (TLR) process is of great concern to the Electric Power Supply Association's (EPSA) members. EPSA is closely monitoring developments in the TLR process at the Federal Energy Regulatory Commission (FERC) as well as changes to these standards, changes in the NAESB Business Practices associated with

Voter	Entity	Segment	Vote	Comment
				TLR, and Interchange Distribution Calculator (IDC) changes being specified and implemented by the Operating Reliability Subcommittee (ORS) and IDC Working Group. Successfully changing the TLR process requires on-going coordination of the work in these various forums. Although EPSA is generally supportive of these standards, the one question that EPSA raises is with respect to the deletion of Table 1 which provides "Examples of Possible System Conditions" in requirement R2.2 of IRO-006-EAST-1. We understand that the Table is now proposed to be included with the Implementation Guideline for Reliability Coordinators (RCs) in the Eastern Interconnection. However, this information is to be used by RCs to identify (requirement R2.2) the appropriate TLR level and to notify (requirement R3.1) all RCs in the Eastern Interconnection of the identified level. Therefore we believe that it would be more appropriate that the Table either be part of the standard or an appendix to it. Doing so would also insure that other registered entities impacted by TLRs would have ready access to this information. We recognize the need for flexibility for RCs to use discretion in selecting the appropriate TLR level based on the circumstances they are facing which may not precisely match any pre-identified criteria. However, the examples contained in the Table are still a needed reference.
Response: The SDT does not believe that including the examples in a supporting document will preclude them from use by entities other than RCs. Not including this information in the standard or as an appendix clearly draws the line between what is required and what is not, and calling specific TLR levels based on specific conditions is not part of the requirement. The SDT will ask the SC for authorization to post the reference document with a link to the associated standard so that the information will be easy to locate.				
Chuck B Manning	Electric Reliability Council of Texas, Inc.	2	Affirmative	The word "valid" is unnecessary
Response: The SDT has eliminated to the use of the word "valid" as proposed.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	Changes to IRO-006-East-1 now require TLR to be posted each hour. This unnecessarily increases compliance documentation without a corresponding system reliability benefit.
Response: Upon further review of the current standard, as well as the current implementation of the IDC, it was determined that such updates are not required for TLR-1. The phrase "with the exception of TLR-1, where an hourly update is not required" was added to the requirement.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	Changes would require TLR to be posted each hour. This unnecessarily increases documentation without a corresponding system reliability benefit.
Response: Upon further review of the current standard, as well as the current implementation of the IDC, it was determined that such updates are not required for TLR-1. The phrase "with the exception of TLR-1, where an hourly update is not required" was added to the requirement.				

Voter	Entity	Segment	Vote	Comment
David A. Lapinski	Consumers Energy	3	Negative	Consumers energy supports the comments of the Midwest ISO
Response: Please see responses to the Midwest ISO.				
James B Lewis	Consumers Energy	5	Negative	Consumers Energy supports the comments of the Midwest ISO.
Response: Please see responses to the Midwest ISO.				
Jim D. Cyrulewski	JDRJC Associates	8	Negative	For IRO-006 East Requirement R2 needs to be clarified on TLR 1 updates, R3.1 - R3.3 need to have IDC added, R4 and R3.3 seem inconsistent.
Response: Upon further review of the current standard, as well as the current implementation of the IDC, it was determined that such updates are not required for TLR-1. The phrase "with the exception of TLR-1, where an hourly update is not required" was added to the requirement. Regarding R3, Parts 3.1 through 3.3, while the IDC may be used to comply with this standard, it is not the only way that entities can comply with the standard. The SDT has intentionally drafted the standard to be implementation neutral. Requirement R3, Part 3.3 addresses the initiating Reliability Coordinator asking the responding Reliability Coordinator(s) to take action. R4 addresses the Responding Coordinator(s) asking their Balancing Authorities to take action (or themselves taking alternate action if conditions so require). Note that Requirement R3, Part 3.3 incorrectly referenced Requirement R2, Part 2.2 – this has been corrected to reference Requirement R2, Part 2.1.				
David Frank Ronk	Consumers Energy	4	Negative	I concur with the comments provided by the Midwest ISO where they said: We vote negative for the following reasons. 1. We are concerned that unavailability or failure of the IDC could render an RC non-compliant with several requirements. Because the IDC is an efficient and effective tool for managing TLRs, RCs typically rely on the IDC to issue the "notification" (IRO-006-EAST-1 R3.1), "list of communication of actions" (IRO-006-EAST-1 R3.2) and "request for congestion management actions" (IRO-006-EAST-1 R3.3). Issuing and managing TLRs would be challenging without the IDC. **Response**: While the IDC may be used to comply with this standard, it is not the only way that entities can comply with the standard. The SDT has intentionally drafted the standard to be implementation neutral. 2. As a result of the RCs reliance on the IDC for TLR management, we are further concerned about the retention of evidence from the IDC. IDC users can gather historical information from the IDC for any TLR that has been issued. However, it is

Voter	Entity	Segment	Vote	Comment
				not clear if an RC must duplicate the information contained in the IDC within their own databases to satisfy compliance auditors. What happens if the an RC relies on the evidence retention in the IDC and the IDC experiences a database failure. Would a compliance auditor be satisfied that the information is not available? Would the RC be held accountable for not being able to present the evidence? **Response**: This is not a deficiency in the standard, but a question between the responsible entity and any other entities with which they work to perform their duties. The SDT recommends that RCs discuss this internally and with any of their related vendors or partners. 3. We are concerned that M4 in IRO-006-EAST-1 is not completely consistent with IRO-006-EAST-1 R4. While R4 allows the receiving RC to completely substitute alternative congestion management actions, M4 appears to inadvertently require some implementation of the original congestion management actions. The problem with the the measurement is the specific language after number 2. The clause "implementing some of the communicated congestion management actions requested by the issuing Reliability Coordinator, and replacing the remainder with" is problematic because we don't believe complete substitution of the original congestion management actions meets the definition of "some". In other words, we believe that none is not included in the definition of some. **Response**: Thank you. The SDT has added “none” to the measure to address this concern. 4. We believe that IRO-006-EAST-1 R2 will render TLR level 1 ineffective and cause RCs to stop using it. R2 incorporates explicitly the need to re-issue TLR level 1 each hour. While previous versions of the standard referenced Attachment 1 which included a guideline to re-issue TLR level 1 each hour, there was no requirement to actually re-issue TLR level 1 every hour because the attachment was not and is not a requirement. **Response**: Upon further review of the current standard, as well as the current implementation of the IDC, it was determined that such updates are not required for TLR-1. The phrase “with the exception of TLR-1, where an hourly update is not required” was added to the requirement.

Voter	Entity	Segment	Vote	Comment
Response: Please see in-line responses.				
Lawrence R. Larson	Otter Tail Power Company	1	Negative	Measure 4 should allow replacing all, not only some, of the original congestion management actions within the constraints of requirement 4. The standard needs to be clearer.
Response: Thank you. The word "none" has been added to the measure to address this concern.				
Charles H Yeung	Southwest Power Pool	2	Negative	Per IRO-EAST-1 R2, TLR 1 will have to be reissued every clock hour. Since there is no operational action required for TLR 1, this serves no reliability purpose and its intent is only to provide the market with updates on the TLR 1 status. However because M2 does not distinguish whether the issuances were made for any particular TLR level, a reliability penalty can be applied for not reissuing a TLR1 for a market benefit. Although SPP supports the changes to the IRO standards and understand benefits to the market of these changes, we see a disconnect from enforcing a requirement for a market benefit through a reliability sanction. In addition, SPP's experience has been our transmission customers do not request hourly updates to TLR 1 status as may be the case in other regions where such information may be crucial. We believe the VSLs should be modified to reflect that only reissuance of TLR 2 and higher will be considered for compliance with IRO-EAST-1 R2.
Response: Upon further review of the current standard, as well as the current implementation of the IDC, it was determined that such updates are not required for TLR-1. The phrase "with the exception of TLR-1, where an hourly update is not required" was added to the requirement. The way the VSLs for R2 have been revised, it is clear that failure to provide an hourly update for TLR-1 is not a violation.				
Charles Locke	Kansas City Power & Light Co.	3	Negative	Per IRO-EAST-1 R2, TLR 1 will have to be reissued every clock hour. Since there is no operational action required for TLR 1, this serves no reliability purpose and only provides the market with updates on the TLR 1 status. However because M2 does not distinguish whether the issuances were made for any particular TLR level, a reliability penalty can be applied for not reissuing a TLR1 for a market benefit. Although KCPL supports the changes to the IRO standards and understand benefits to the market of some of these changes, we see a disconnect from enforcing a requirement for a market benefit with a reliability sanction. In addition, transmission customers do not request hourly updates to TLR 1 status as may be the case in other regions where such information may be crucial. We believe the VSLs should be modified to reflect that only reissuance of TLR 2 and higher will be considered for compliance with IRO-EAST-1 R2.
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George T. Ballew	Tennessee Valley Authority	5	Negative	Per IRO-EAST-1 R2, TLR 1 will have to be reissued every clock hour. Since there is no operational action required for TLR 1, this serves no reliability purpose and only provides the market with updates on the TLR 1 status. However because M2 does not distinguish whether the issuances were made for any particular TLR level, a reliability penalty can be applied for not reissuing a TLR1 for a market benefit. Although TVA SPP supports the changes to the IRO standards and understand benefits to the market of some of these changes, we see a disconnect from enforcing a requirement for a market benefit with a reliability sanction. In addition, SPP's experience has been our transmission customers do not request hourly updates to TLR 1 status as may be the case in other regions where such information may be crucial. We believe the VSLs should be modified to reflect that only reissuance of TLR 2 and higher will be considered for compliance with IRO-EAST-1 R2.
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Thomas Saitta	Kansas City Power & Light Co.	6	Negative	Per IRO-EAST-1 R2, TLR 1 will have to be reissued every clock hour. Since there is no operational action required for TLR 1, this serves no reliability purpose and only provides the market with updates on the TLR 1 status. However because M2 does not distinguish whether the issuances were made for any particular TLR level, a reliability penalty can be applied for not reissuing a TLR1 for a market benefit. Although KCPL supports the changes to the IRO standards and understand benefits to the market of some of these changes, we see a disconnect from enforcing a requirement for a market benefit with a reliability sanction. In addition, transmission customers do not request hourly updates to TLR 1 status as may be the case in other regions where such information may be crucial. We believe the VSLs should be modified to reflect that only reissuance of TLR 2 and higher will be considered for compliance with IRO-EAST-1 R2.
Response: Upon further review of the current standard, as well as the current implementation of the IDC, it was determined that such updates are not required for TLR-1. The phrase "with the exception of TLR-1, where an hourly update is not required" was added to the requirement. The way the VSLs for R2 have been revised, it is clear that failure to provide an hourly update for TLR-1 is not a violation.				

Voter	Entity	Segment	Vote	Comment
Lee Schuster	Florida Power Corporation	3	Negative	Progress is voting Negative on IR0-006-EAST-1 and proposes the following changes to IR0-006-EAST-1 to clarify and improve the standard, and to possibly correct an error. 1) In the first bullet item of R1, add the words “of generation” so the bullet reads: “Inter-area redispatch of generation.” This bullet item will then be consistent with the second bullet item. **Response**: Thank you. The suggested change has been made. 2) In the last bullet item of R1, the use of the word “Involuntary” is not clear. All “load reductions” by their nature are involuntary, even DSM. A better word would be “Controlled”. **Response**: Thank you. The suggested change has been made. 3) NERC is proposing to revise R2 so that R2.1 will be a list of congestion management actions, and R2.2 will be a list of TLR levels. However, it appears that R3.3 would now also need to be revised. Should R3.3 refer to “Part 2.1” and not “Part 2.2”? **Response**: Thank you. A correction has been made to address this concern.
Response: Please see in-line responses.				
Wayne Lewis	Progress Energy Carolinas	5	Negative	Progress is voting Negative on IR0-006-EAST-1 and proposes the following changes to IR0-006-EAST-1 to clarify and improve the standard, and to possibly correct an error. 1) In the first bullet item of R1, add the words “of generation” so the bullet reads: “Inter-area redispatch of generation.” This bullet item will then be consistent with the second bullet item. **Response**: Thank you. The suggested change has been made. 2) In the last bullet item of R1, the use of the word “Involuntary” is not clear. All “load

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				reductions" by their nature are involuntary, even DSM. A better word would be "Controlled". **Response**: Thank you. The suggested change has been made. 3) NERC is proposing to revise R2 so that R2.1 will be a list of congestion management actions, and R2.2 will be a list of TLR levels. However, it appears that R3.3 would now also need to be revised. Should R3.3 refer to "Part 2.1" and not "Part 2.2"? **Response**: Thank you. A correction has been made to address this concern.
Response: Please see in-line responses.				
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	Proposed Comments on Project 2006-08 for Negative Vote Revised standard IRO-006 standard allows a responsible entity to provide "valid" reliability reasons when not complying with a TLR directive. The standard needs to identify those reasons that NERC believes are valid as well as the data required to support each reason. The standard should also identify the party responsible for determining whether the reason given for not complying with a TLR order is valid. E.ON U.S. suggests that the Regional Entity make that determination only after NERC and/or the Commission provide what each believes to be appropriate reasons to ignore a TLR order.
Response: The SDT believes that, given the diversity of conditions and configurations that may be seen during real-time operations, trying to identify a list of potential reasons for not complying would be extremely challenging. Like all other elements associated with verifying that compliance with the standard occurred, reasons will be evaluated by the Compliance Enforcement Authority. Note that due to concerns expressed by other commenters, the SDT has removed the word "valid" from the requirement.				
Charles A. Freibert	Louisville Gas and Electric Co.	3	Negative	Revised standard IRO-006 standard allows a responsible entity to provide "valid" reliability reasons when not complying with a TLR directive. The standard needs to identify those reasons that NERC believes are valid as well as the data required to support each reason. The standard should also identify the party responsible for determining whether the reason given for not complying with a TLR order is valid. E.ON U.S. suggests that the Regional Entity make that determination only after NERC and/or the Commission provide what each believes to be appropriate reasons to ignore a TLR order.

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Daryn Barker	Louisville Gas and Electric Co.	6	Negative	Revised standard IRO-006 standard allows a responsible entity to provide "valid" reliability reasons when not complying with a TLR directive. The standard needs to identify those reasons that NERC believes are valid as well as the data required to support each reason. The standard should also identify the party responsible for determining whether the reason given for not complying with a TLR order is valid. E.ON U.S. suggests that the Regional Entity make that determination only after NERC and/or the Commission provide what each believes to be appropriate reasons to ignore a TLR order.
Response: The SDT believes that, given the diversity of conditions and configurations that may be seen during real-time operations, trying to identify a list of potential reasons for not complying would be extremely challenging. Like all other elements associated with verifying that compliance with the standard occurred, reasons will be evaluated by the Compliance Enforcement Authority. Note that due to concerns expressed by other commenters, the SDT has removed the word "valid" from the requirement.				
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	The proposed requirements for TLR 1 do not provide any added benefit to reliability and create an increased burden on the real time System operators.
Response: Upon further review of the current standard, as well as the current implementation of the IDC, it was determined that such updates are not required for TLR-1. The phrase "with the exception of TLR-1, where an hourly update is not required" was added to the requirement.				
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Negative	The Standard indicated that if a RC or BA did not comply with request from RC, BA, or TOP of another interconnection , it must provide a "valid" reason. No indication is given concerning who determines validity or how validity is determined. The draft standard was modified to change the language concerning the reason of not acting on a request from "a" reliability reason to any "a valid" reliability reason. Without the clarification, the standard would not be enforceable as it pertains to requests for curtailment that were not acted on. Furthermore, the insertion of the term "valid" implies that an RC or BA would not be acting in the true interests of BES reliability by providing "invalid" reliability reasons for not providing loading relief.
Response: The SDT has eliminated to the use of the word "valid" as proposed.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	We vote negative for the following reasons. 1. As a result of the Reliability Coordinators' reliance on the IDC for TLR management,

Voter	Entity	Segment	Vote	Comment
				we are concerned about the retention of evidence from the IDC. IDC users can gather historical information from the IDC for any TLR that has been issued. However, it is not clear if an RC must duplicate the information contained in the IDC within their own databases to satisfy compliance auditors. What happens if an RC relies on the evidence retention in the IDC and the IDC experiences a database failure? Would a compliance auditor be satisfied that the information is not available? Would the RC be held accountable for not being able to present the evidence? **Response**: While the IDC may be used to comply with this standard, it is not the only way that entities can comply with the standard. The SDT has intentionally drafted the standard to be implementation neutral. 2. We are concerned that M4 in IRO-006-EAST-1 is not completely consistent with IRO-006-EAST-1 R4. While R4 allows the receiving RC to completely substitute alternative congestion management actions, M4 appears to inadvertently require some implementation of the original congestion management actions. The problem with the measurement is the specific language after number 2. The clause "implementing some of the communicated congestion management actions requested by the issuing Reliability Coordinator, and replacing the remainder with" is problematic because we don't believe complete substitution of the original congestion management actions meets the definition of "some". In other words, we believe that “none” is not included in the definition of “some”. **Response**: Thank you. The word “none” has been added to the measure to address this concern. 3. We believe that IRO-006-EAST-1 R2 will render TLR level 1 ineffective and cause RCs to stop using it. R2 incorporates explicitly the need to re-issue TLR level 1 each hour. While previous versions of the standard referenced Attachment 1 which included a guideline to re-issue TLR level 1 each hour, there was no requirement to actually re-issue TLR level 1 every hour because the attachment was not and is not a requirement. **Response**: Upon further review of the current standard, as well as the current implementation of the IDC, it was determined that such updates are not required for TLR-1. The phrase “with the exception of TLR-1, where an hourly update is not required” was added to the requirement.

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Response: Please see in-line responses.				

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Non-binding Poll Name:	**Project 2006-08 - Reliability Coordination - Transmission Loading Relief - Non-binding Poll for VRFs and VSLs**
Poll Period:	6/23/2010 - 7/6/2010
Total # Opinions:	198
Total Ballot Pool:	247
Summary Results:	80% of those who registered to participate provided an opinion; 86% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed

Individual Ballot Pool Results

Segment	Organization	Member	Opinion	Comments
1	Ameren Services	Kirit S. Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	Avista Corp.	Scott Kinney	Abstain	
1	BC Transmission Corporation	Gordon Rawlings	Abstain	
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Abstain	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	John K Loftis	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett		
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg		
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lake Worth Utilities	Walt Gill	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Abstain	

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1	National Grid	Saurabh Saksena	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Mark Sampson	Abstain	
1	Portland General Electric Co.	Frank F. Afranji		
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Abstain	
1	San Diego Gas & Electric	Linda Brown	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo		
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry Akens		
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Abstain	
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	California ISO	Timothy VanBlaricom	Abstain	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Abstain	
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	

2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool	Charles H Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	American Electric Power	Raj Rana	Affirmative	View
3	Arizona Public Service Co.	Thomas R. Glock		
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Abstain	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone		
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Abstain	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	New York Power Authority	Marilyn Brown	Negative	
3	Niagara Mohawk (National Grid	Michael Schiavone	Affirmative	

	Company)			
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PacifiCorp	John Apperson	Abstain	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Abstain	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Wisconsin Electric Power Marketing	James R. Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	
4	Consumers Energy	David Frank Ronk	Abstain	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Abstain	
5	City of Tallahassee	Alan Gale	Abstain	
5	Conectiv Energy Supply, Inc.	Kara Dundas		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis	Negative	View
5	Detroit Edison Company	Christy Wicke		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Electric Power Supply Association	Jack R. Cashin		
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Cynthia E Sulzer		
5	Kissimmee Utility Authority	Mike Blough	Abstain	

5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Louisville Gas and Electric Co.	Charlie Martin	Negative	View
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	Nebraska Public Power District	Jon Sunneberg	Abstain	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Otter Tail Power Company	Ward Uggerud	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Mark A. Heimbach	Abstain	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Power LLC	David Murray	Abstain	
5	Sacramento Municipal Utility District	Bethany Wright	Abstain	
5	Salt River Project	Glen Reeves	Abstain	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Negative	View
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	Barry Green Consulting Inc.	Barry Green	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Abstain	
6	Cleco Power LLC	Matthew D Cripps	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S Slade	Abstain	
6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	

6	NRG Energy, Inc.	Alan R. Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	
6	Progress Energy	James Eckelkamp		
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Salt River Project	Mike Hummel	Abstain	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	South Carolina Electric & Gas Co.	Matt H Bullard	Abstain	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini	Abstain	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Project 2006-08 — Reliability Coordination — Transmission Loading Relief — Non-binding Poll for VRFs and VSLs

Date of Initial Ballot: June 23, 2010 – July 6, 2010

Summary Consideration:

One entity suggested that the VSLs should be modified to have “pass/fail” requirements with VSLs other than “Severe.” To do so would be a violation of FERC’s VSL Guidelines (Guideline 2).

Some entities objected to the use of the word ”valid” in the standards and the VSLs. The word has been removed.

Some entities objected to the obligation to reissue a TLR-1 every hour. The standard was modified to remove this obligation.

Two entities suggested that a violation of IRO-005-5 R1 should not have a “high” VRF, as they believe that the risk associated with being imbalanced across Interconnections is not significant enough to warrant the “high” designation. The team believes that the majority of the industry agrees with the drafting team that such risk does exist and is significant enough to qualify for assignment of a “high” VRF. An entity in another interconnection that does not curtail as requested will leave its interconnection unbalanced, which could contribute to BES instability, one of the key criteria for establishing a High VRF. Further, projects in the future may expand scheduling capabilities between Interconnections, making that risk even greater than it is today.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Raj Rana	American Electric Power	3	Affirmative	AEP does not have a problem with the minor change to the VSL related to the change to the requirement. However, AEP does not agree with respect to a "pass/fail" VSL automatically be assigned to the "Severe" level. This is arbitrary assignment and it can be debated that any of the other VSL levels would be appropriate, preferably starting at the lower level.
Response: A Pass/Fail requirement has been established as requiring the assignment of a VSL of ”Severe” as part of FERC VSL Guideline 2. At this point, VSLs must comply with the established FERC guidelines, including Guideline 2.				
Edward P. Cox	AEP Marketing	6	Affirmative	AEP does not have a problem with the minor change to the VSL related to the change to the requirement. However, AEP does not agree with respect to a "pass/fail" VSL automatically be assigned to the "Severe" level. This is arbitrary assignment and it can be debated that any of the VSL levels would be appropriate.

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Response: A Pass/Fail requirement has been established as requiring the assignment of a VSL of "Severe" as part of FERC VSL Guideline 2. At this point, VSLs must comply with the established FERC guidelines, including Guideline 2.				
Kevin Querry	FirstEnergy Solutions	3	Affirmative	No Comment
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Negative	For the reasons cited concerning the term "valid". In addition, the VSL's do not appear to be based on reliability impact. The VSL's should have a basis for impact on reliability and as such it would be expected to have moderate to lower levels if severity.
Response: The team has eliminated the word "valid" from the standard. Note that VSLs are not based on "impact to reliability;" the Violation Risk Factor serves this function.				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	Per IRO-EAST-1 R2, TLR 1 will have to be reissued every clock hour. Since there is no operational action required for TLR 1, this serves no reliability purpose and only provides the market with updates on the TLR 1 status. However because M2 does not distinguish whether the issuances were made for any particular TLR level, a reliability penalty can be applied for not reissuing a TLR1 for a market benefit. Although KCPL supports the changes to the IRO standards and understand benefits to the market of some of these changes, we see a disconnect from enforcing a requirement for a market benefit with a reliability sanction. In addition, transmission customers do not request hourly updates to TLR 1 status as may be the case in other regions where such information may be crucial. We believe the VSLs should be modified to reflect that only reissuance of TLR 2 and higher will be considered for compliance with IRO-EAST-1 R2.
Response: The standard has been modified as suggested.				
Charles H Yeung	Southwest Power Pool	2	Negative	Per IRO-EAST-1 R2, TLR 1 will have to be reissued every clock hour. Since there is no operational action required for TLR 1, this serves no reliability purpose and its intent is only to provide the market with updates on the TLR 1 status. However because M2 does not distinguish whether the issuances were made for any particular TLR level, a reliability penalty can be applied for not reissuing a TLR1 for a market benefit. Although SPP supports the changes to the IRO standards and understand benefits to the market of these changes, we see a disconnect from enforcing a requirement for a market benefit through a reliability sanction. In addition, SPP's experience has been our transmission customers do not request hourly updates to TLR 1 status as may be the case in other regions where such information may be crucial. We believe the VSLs should be modified to reflect that only reissuance of TLR 2 and higher will be considered for compliance with IRO-EAST-1 R2.
Response: The standard has been modified as suggested.				

Voter	Entity	Segment	Vote	Comment
Charles Locke	Kansas City Power & Light Co.	3	Negative	Per IRO-EAST-1 R2, TLR 1 will have to be reissued every clock hour. Since there is no operational action required for TLR 1, this serves no reliability purpose and only provides the market with updates on the TLR 1 status. However because M2 does not distinguish whether the issuances were made for any particular TLR level, a reliability penalty can be applied for not reissuing a TLR1 for a market benefit. Although KCPL supports the changes to the IRO standards and understand benefits to the market of some of these changes, we see a disconnect from enforcing a requirement for a market benefit with a reliability sanction. In addition, transmission customers do not request hourly updates to TLR 1 status as may be the case in other regions where such information may be crucial. We believe the VSLs should be modified to reflect that only reissuance of TLR 2 and higher will be considered for compliance with IRO-EAST-1 R2.
Response: The standard has been modified as suggested.				
George T. Ballew	Tennessee Valley Authority	5	Negative	Per IRO-EAST-1 R2, TLR 1 will have to be reissued every clock hour. Since there is no operational action required for TLR 1, this serves no reliability purpose and only provides the market with updates on the TLR 1 status. However because M2 does not distinguish whether the issuances were made for any particular TLR level, a reliability penalty can be applied for not reissuing a TLR1 for a market benefit. Although TVA SPP supports the changes to the IRO standards and understand benefits to the market of some of these changes, we see a disconnect from enforcing a requirement for a market benefit with a reliability sanction. In addition, SPP's experience has been our transmission customers do not request hourly updates to TLR 1 status as may be the case in other regions where such information may be crucial. We believe the VSLs should be modified to reflect that only reissuance of TLR 2 and higher will be considered for compliance with IRO-EAST-1 R2.
Response: The standard has been modified as suggested.				
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	Per IRO-EAST-1 R2, TLR 1 will have to be reissued every clock hour. Since there is no operational action required for TLR 1, this serves no reliability purpose and only provides the market with updates on the TLR 1 status. However because M2 does not distinguish whether the issuances were made for any particular TLR level, a reliability penalty can be applied for not reissuing a TLR1 for a market benefit. Although KCPL supports the changes to the IRO standards and understand benefits to the market of some of these changes, we see a disconnect from enforcing a requirement for a market benefit with a reliability sanction. In addition, transmission customers do not request hourly updates to TLR 1 status as may be the case in other regions where such information may be crucial. We believe the VSLs should be modified to reflect that only reissuance of TLR 2 and higher will be considered for compliance with IRO-EAST-1 R2.

Voter	Entity	Segment	Vote	Comment
Response: The standard has been modified as suggested.				
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	Proposed Comments on Project 2006-08 for Negative Vote Revised standard IRO-006 standard allows a responsible entity to provide "valid" reliability reasons when not complying with a TLR directive. The standard needs to identify those reasons that NERC believes are valid as well as the data required to support each reason. The standard should also identify the party responsible for determining whether the reason given for not complying with a TLR order is valid. E.ON U.S. suggests that the Regional Entity make that determination only after NERC and/or the Commission provide what each believes to be appropriate reasons to ignore a TLR order.
Response: The team has eliminated the word "valid" from the standard.				
James B Lewis	Consumers Energy	5	Negative	See the Midwest ISO comments.
Response: Please see Midwest ISO responses.				
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	The proposed requirements for TLR 1 do not provide any added benefit to reliability and create an increased burden on the real time System operators.
Response: The standard has been modified to remove the requirement to reissue TLR 1 every hour.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	We disagree with a High VRF for IRO-006-5 R1. It does not consider the physical capabilities of interchange between Interconnections. We do not believe scheduling capabilities between Interconnections are large enough for a significant volume of schedules to occur. Thus, curtailment of the schedules may have some minor impact on frequency but it is not large enough to cause directly BES instability solely from a violation of this requirement.
Response: Only 2 comments were received indicating concern with this VRF. The team believes that the majority of commenters agree with the drafting team that such risk does exist and warrants the "high" VRF assignment. An entity in another interconnection that does not curtail as requested will leave its Interconnection unbalanced, which could contribute to BES instability, one of the key criteria in establishing a High VRF. Further, projects in the future may expand scheduling capabilities between Interconnections, making that risk even greater than it is today.				

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 the SAR and assembled a drafting team on December 5, 2006.
2. The revisions to IRO-006 to transfer business practice content to NAESB were approved as IRO-006-4 by the Board of Trustees on October 23, 2007.
3. The SDT developed a first draft for industry consideration and posted it for comments from October 30, 2008 to December 1, 2008.
4. The SDT developed a second draft for industry consideration and posted it for comments from October 30, 2008 to December 1, 2008.
5. The SDT developed a third draft for industry consideration and posted it for comments from July 13, 2009 to August 13, 2009.
6. The SDT developed a fourth draft for industry consideration and posted it for comments from October 27, 2009 to November 30, 2009.
7. The SDT developed a fifth draft for industry consideration and posted it for initial ballot from June 23, 2010 to July 6, 2010.
8. The SDT has developed this sixth and final draft for industry consideration.

Proposed Action Plan and Description of Current Draft:

This is the sixth and final draft of the proposed standard. It is being posted for Recirculation Ballot.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
Respond to comments.	August 11, 2010
Recirculation ballot.	August 20, 2010
Board adoption.	November 3, 2010

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.

None.

A. Introduction

1. **Title: Reliability Coordination — Transmission Loading Relief (TLR)**

2. **Number: IRO-006-5**

3. **Purpose:** To ensure coordinated action between Interconnections when implementing Interconnection-wide transmission loading relief procedures to prevent or manage potential or actual SOL and IROL exceedances to maintain reliability of the bulk electric system.

4. **Applicability:**

   4.1. Reliability Coordinator.

   4.2. Balancing Authority.

5. **Proposed Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Reliability Coordinator and Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a ~~valid~~ reliability reason to the requestor ~~that~~why it cannot comply with the request. [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall provide evidence (such as dated logs, voice recordings, Tag histories, and studies, in electronic or hard copy format) that, when a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure was made from another Reliability Coordinator, Balancing Authority, or Transmission Operator in that other Interconnection, it complied with the request or provided a ~~valid~~ reliability reason ~~that~~why it could not comply with the request (R1).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   Regional Entity.

1.2. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.3. Data Retention

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

- The Reliability Coordinator and Balancing Authority shall maintain evidence to show compliance with R1 for the most recent twelve calendar months plus the current month.
- If a Reliability Coordinator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				The responsible entity received a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority, or Transmission Operator, but the entity neither complied with the request, nor provided a ~~valid~~ reliability reason why it could not comply with the request.

E. Variances

None.

F. Associated Documents

None.

G. 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
4	October 23, 2007	Completed NERC/NAESB split	Revision
5	TBD	Removed Attachment 1 and made into a new standard, eliminated unnecessary requirements.	Revision

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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.

~~**Reallocation:** The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.~~ (To be retired.)

Market Flow: the total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve Load internal to the market.

A. Introduction

1. **Title: Transmission Loading Relief Procedure for the Eastern Interconnection**

2. **Number:** IRO-006-EAST-1

3. **Purpose:** To provide an Interconnection-wide transmission loading relief procedure (TLR) for the Eastern Interconnection that can be used to prevent and/or mitigate potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).

4. **Applicability:**

   4.1. Reliability Coordinators in the Eastern Interconnection.

5. **Proposed Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_V, each Reliability Coordinator shall initiate, prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated), one or more of the following actions: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

- Inter-area redispatch of generation
- Intra-area redispatch of generation
- Reconfiguration of the transmission system
- Voluntary load reductions (e.g., Demand-side Management)
- ~~Involuntary~~Controlled load reductions (e.g., load shedding)

R2. ~~In order to~~To ensure operating entities are provided with information needed to maintain an awareness of changes to the Transmission System, when initiating the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance, and at least every clock hour (with the exception of TLR-1, where an hourly update is not required) after initiation up to and including the hour when the TLR level has been identified as TLR Level 0, the Reliability Coordinator shall identify: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

2.1. A list of congestion management actions to be implemented, and

2.2. One of the following TLR levels: TLR-1, TLR-2, TLR-3A, TLR-3B, TLR-4, TLR-5A, TLR-5B, TLR-6, TLR-0 [1]

[1] For more information on TLR levels, please see "Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels Reference Document."

R3. Upon the identification of the TLR level and a list of congestion management actions to be implemented, the Reliability Coordinator initiating this TLR procedure shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

3.1. Notify all Reliability Coordinators in the Eastern Interconnection of the identified TLR level

3.2. Communicate the list of congestion management actions to be implemented to 1.) all Reliability Coordinators in the Eastern Interconnection, and 2.) those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions.

3.3. Request that the congestion management actions identified in Requirement R2, Part 2.~~2~~1 be implemented by:

1.) Each Reliability Coordinator associated with a Sink Balancing Authority for which Interchange Transactions are to be curtailed,

2.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which Network Integration Transmission Service or Native Load is to be curtailed, and

3.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which its Market Flow is to be curtailed.

R4. Each Reliability Coordinator that receives a request as described in Requirement R3, Part 3.3. shall, within 15 minutes of receiving the request, implement the ~~communicated~~ congestion management actions requested by the issuing Reliability Coordinator as follows: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

- Instruct its Balancing Authorities to implement the Interchange Transaction schedule change requests.
- Instruct its Balancing Authorities to implement the Network Integration Transmission Service and Native Load schedule changes for which the Balancing Authorities are responsible.
- Instruct its Balancing Authorities to implement the Market Flow schedule changes for which the Balancing Authorities are responsible.
- If an assessment ~~determines~~shows that one or more of the congestion management actions communicated in Requirement R3, Part 3.3 will result in a reliability concern or will be ineffective, the Reliability Coordinator may replace those specific actions with alternate congestion management actions, provided that:
    - The alternate congestion management actions have been agreed to by the initiating Reliability Coordinator, and
    - The ~~Assessment~~ assessment shows that the alternate congestion management actions will not adversely affect reliability.

C. Measures

M1. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that when acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_v, the Reliability Coordinator initiated one or more of the actions listed in R1 prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated)(R1).

M2. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that at the time it initiated the Eastern Interconnection TLR procedure, and at least every clock hour after initiation up to and including the hour when the TLR level was identified as TLR Level 0, the Reliability Coordinator identified both the TLR Level and a list of congestion management actions to be implemented (R2).

M3. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that after it identified a TLR level and a list of congestion management actions to take, it 1.) notified all Reliability Coordinators in the Eastern Interconnection of the TLR Level, 2.) communicated the list of actions to all Reliability Coordinators in the Eastern Interconnection and those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions, and 3.) requested the Reliability Coordinators identified in Requirement R3 Part 3.2 to implement the congestion management actions identified in Requirement R2 Part 2.~~2~~1 (R3).

M4. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that within fifteen minutes of the receipt of a request as described in R3, the Reliability Coordinator complied with the request by either 1.) implementing the communicated congestion management actions requested by the issuing Reliability Coordinator, or 2.) implementing none or some of the communicated congestion management actions requested by the issuing Reliability Coordinator, and replacing the remainder with alternate congestion management actions if assessment showed that some or all of the congestion management actions communicated in R3 would have resulted in a reliability concern or would have been ineffective, the alternate congestion management actions were agreed to by the initiating Reliability Coordinator, and assessment showed that the alternate congestion management actions would not adversely affect reliability (R4).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications

- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.3. Data Retention

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

- The Reliability Coordinator shall maintain evidence to show compliance with R1, R2, R3, and R4 for the past 12 months plus the current month.
- If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

3. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_v, the Reliability Coordinator did not initiate one or more of the actions listed under R1 prior to or in conjunction with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated).
R2	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for one clock hour during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for two clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for three clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for four or more clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The initiating Reliability Coordinator did not notify one or more Reliability Coordinators in the Eastern Interconnection of the TLR Level (3.1).	N/A	The initiating Reliability Coordinator did not communicate the list of congestion management actions to one or more of the Reliability Coordinators listed in Requirement R3, Part 3.2. OR The initiating Reliability Coordinator requested some, but not all, of the Reliability Coordinators identified in Requirement R3, Part 3.3 to implement the identified congestion management actions.	The initiating Reliability Coordinator requested none of the Reliability Coordinators identified in Requirement R3, Part 3.3 to implement the identified congestion management actions.
R4				The responding Reliability Coordinator did not, within 15 minutes of receiving a request, either 1.) implement all the requested congestion management actions, or 2.) implement none or some of the requested congestion management actions and replace the remainder with alternate congestion

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				management actions, provided that: assessment showed that the actions replaced would have resulted in a reliability concern or would have been ineffective, the alternate congestion management actions were agreed to by the initiating Reliability Coordinator, and assessment determined that the alternate congestion management actions would not adversely affect reliability.

E. Variances

None.

F. Associated Documents

~~TLR Level~~ Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels Reference Document

G. Revision History

Version	Date	Action	Tracking
1		Creation of new standard, incorporating concepts from IRO-006-4 Attachment; elimination of Regional Differences, as the standard allows the use of Market Flow	New

Implementation Plan for Standard IRO-006-5 (Reliability Coordination — Transmission Loading Relief (TLR)) and IRO-006-EI-1 (Loading Relief Procedure for the Eastern Interconnection)

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved or in progress, that must be implemented before these standards can be implemented.

Modified Definitions

The definition of “Reallocation” should be removed from the Glossary when IRO-006-5 and IRO-006-EI-1 become effective. The drafting team has verified that the term, “Reallocation” is not used in any other approved standard.

Modified Standards

IRO-006-4, and associated Attachment 1, should be retired when IRO-006-5 and IRO-006-EI-1 become effective.

The Regional Differences within IRO-006-4 should be retired when IRO-006-5 and IRO-006-EI-1 become effective.

Compliance with Standards

Once the standards become effective, the responsible entities identified in the applicability section of the standards must comply with the requirements. These include:

- Reliability Coordinators
- Balancing Authorities

Proposed Effective Date

The standards will become effective on the first day of the first calendar quarter after the date the standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standards becomes effective on the first day of the first calendar quarter after the date the standards are approved by the NERC Board of Trustees.

Ballot Results	
Ballot Name:	Project 2006-08 - Reliability Coordination - Transmission Loading Relief _rc
Ballot Period:	8/20/2010 - 8/30/2010
Ballot Type:	recirculation
Total # Votes:	218
Total Ballot Pool:	247
Quorum:	**88.26 % The Quorum has been reached**
Weighted Segment Vote:	93.93 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

			Affirmative		Negative		Abstain	
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	# Votes	No Vote
1 - Segment 1.	69	1	48	0.941	3	0.059	11	7
2 - Segment 2.	10	0.9	8	0.8	1	0.1	0	1
3 - Segment 3.	56	1	36	0.9	4	0.1	7	9
4 - Segment 4.	15	1	14	0.933	1	0.067	0	0
5 - Segment 5.	43	1	28	0.966	1	0.034	9	5
6 - Segment 6.	34	1	22	0.917	2	0.083	6	4
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.5	5	0.5	0	0	1	0
9 - Segment 9.	6	0.4	4	0.4	0	0	1	1
10 - Segment 10.	8	0.5	5	0.5	0	0	1	2
Totals	**247**	**7.3**	**170**	**6.857**	**12**	**0.443**	**36**	**29**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	Avista Corp.	Scott Kinney	Abstain	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Abstain	
1	Central Maine Power Company	Brian Conroy	Affirmative	

1	City of Vero Beach	Randall McCamish	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	John K Loftis	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	View
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett		
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg		
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lake Worth Utilities	Walt Gill	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	National Grid	Saurabh Saksena	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Mark Sampson	Abstain	
1	Portland General Electric Co.	Frank F. Afranji	Abstain	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Abstain	
1	San Diego Gas & Electric	Linda Brown	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Abstain	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Affirmative	View
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	California ISO	Timothy VanBlaricom	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	

2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool	Charles H Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock		
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Abstain	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Negative	View
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone		
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Negative	
3	Lincoln Electric System	Bruce Merrill	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Abstain	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Abstain	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Wisconsin Electric Power Marketing	James R. Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	

4	Consumers Energy	David Frank Ronk	Negative	View
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Abstain	
5	City of Tallahassee	Alan Gale	Affirmative	
5	Conectiv Energy Supply, Inc.	Kara Dundas		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy	James B Lewis	Negative	View
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Electric Power Supply Association	Jack R. Cashin	Affirmative	View
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Cynthia E Sulzer		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	Nebraska Public Power District	Jon Sunneberg	Abstain	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Otter Tail Power Company	Ward Uggerud	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Mark A Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	PSEG Power LLC	David Murray	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Abstain	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	George T. Ballew	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Affirmative	View
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Barry Green Consulting Inc.	Barry Green	Affirmative	View
6	Bonneville Power Administration	Brenda S. Anderson	Abstain	
6	Cleco Power LLC	Matthew D Cripps	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Abstain	
6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery		

6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan R. Johnson	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Salt River Project	Mike Hummel	Abstain	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	View
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		

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