NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

NERC-NAESB-ISO/RTO Council Joint Interface Committee Conference Call

January 12, 2006

Conference Call Information	**WebEx Information**
Time: 2–5 p.m. EST	Time: 2–5 p.m. EST
Telephone: 732-694-2061	Meeting Number: 711 560 684
Access Code: 3560061	Meeting Password: 3560061
Conference Code: 10000112	Conference Code: 10000112
Facilitator: Don Benjamin	Web Cast URL: https://nerc.webex.com

Meeting Agenda

1. **Administration**
2. **NERC, NAESB, and IRC Annual Plans**
3. **NERC SAR to revise IRO-006-0, "Transmission Loading Relief" and NAESB Business Practice Request**
4. **SAR to revise EOP-004, "Disturbance Reporting"**
5. **RO5004 TTC/ATC/AFC/CBM/TRM in Requesting and Scheduling Transmission Service**
6. **TLR Coordination Procedure**
7. **Next Meeting**

Item 1. Administration

The JIC secretary will handle these items. The NAESB staff will read the anti-trust compliance guidelines.

a. Roll call
b. Roster and Membership Changes (**Item 1b**)
c. Establish Quorum
d. Antitrust Guidelines (**Item 1d**)
e. Prior Meeting Minutes (**Item 1e**)
f. Agenda

Item 2. NERC, NAESB, and IRC Annual Plans

Action

Review NERC, NAESB, and IRC annual plans.

Attachments

a. NAESB WEQ 2006 Annual Plan – Rae McQuade (**Item 2a**)

b. IRC 2006 Annual plan – Charles Yeung (**Item 2b**)

c. NERC (SAC) 2006 Annual Plan (will be sent separately) – Linda Campbell (**Item 2c**)

Background

The NERC/NAESB/IRC Memorandum of Understanding explains that the JIC will review the annual plans of the three organizations, determine whether an annual plan item could affect ISO and RTO policy, and recommend changes to any party's annual plan to carry out the purposes of the MOU.

Here is an excerpt from the MOU that explains the annual plan review:

> 2.4 The JIC will meet as necessary to review the annual plans of each organization. Additionally, the JIC will meet as necessary to review each Standards Authorization Request ("SAR") that the Standards Authorization Committee ("SAC") of NERC has approved for the drafting of a standard, each standard request that the NAESB Executive Committee ("EC") has assigned to the Wholesale Electric Quadrant ("WEQ") of NAESB and each ISO and RTO policy anticipated to be proposed or implemented by the ISO/RTO Council's constituent organizations that may affect business practice standards and reliability standards.
>
> 2.5 In the first stage of its process, the JIC will evaluate the annual plans of each Party. If the JIC determines that an annual plan item would establish or require substantial modification to ISO and RTO policy, then standard setting activities associated with the annual plan item would normally be deferred until the FERC or other appropriate regulatory authorities in North America have exercised their authority to determine such policy issues. Once such ISO and RTO policy issues have been resolved, further standards development activity will be coordinated by the JIC according to this MOU. If the JIC does not determine that an annual plan item would establish or require substantial modification to ISO and RTO policy, then the item would continue through the standards

development process. If the JIC determines that an aspect of the ISO/RTO Council's annual plans would alter or require new business practice standards, communication protocol standards or reliability standards, those standards development activities would be coordinated by the JIC according to this MOU. The JIC may also recommend that a particular item or aspect of an item in one Party's annual plan be removed from that Party's annual plan and added to another Party's annual plan in order to carry out the purposes of this agreement.

Item 3. NERC SAR to Revise IRO-006-0, "Transmission Loading Relief" and NAESB Business Practice Request

Action

Assign to NERC for standard drafting and to NAESB for business practice drafting.

Larry Kezele will be available to answer questions about these requests.

Attachments

a. SAR, "Modification to IRO-006-1 to allow Market Flow Information as input to IDC" (**Item 3a)**

b. NAESB business practice request (will be sent separately) (**Item 3b**)

c. Draft Standard IRO-006, "Transmission Loading Relief" (markup) (**Item 3c**)

Background

This SAR is primarily intended to incorporate the term "market flow" to the reliability standard. The market flow is the energy flow on a flowgate that the balancing authority (or market operator) determines from its market dispatch. The balancing authority or market operator then uploads these market flow calculations directly to the Interchange Distribution Calculator.

NERC added the market flow provision to the TLR procedure through a waiver when PJM began its market operations. When MISO began its market, NERC added MISO to the market flow waiver.

Recently, Southwest Power Pool announced its plans to begin market operations in May 2006, and NERC staff suggested that the waiver (which, technically, no longer exists in the collection of reliability standards documents) be incorporated into the standard. This would also allow future market operators—as well as non-market balancing authorities—to enter their "market flows" (security-constrained dispatch) into the IDC without necessitating a change to the reliability standard.

The standards authorization request is attached for JIC assignment. We have also attached the draft standard, which, though not authorized, is quite straightforward.

Coordination with NAESB. NERC and NAESB staffs are working on a procedure that will keep the reliability and business parts of the TLR procedure synchronized. However, this procedure needs additional work; indeed, at this point it is not clear whether the TLR procedure will be divided between NERC and NAESB, or remain intact.

On December 16, 2005, Michael Desselle, Larry Kezele, Kathy York, Joel Dison, Mark Ladrow, and Don Benjamin met by conference call and agreed that NERC and NAESB would continue to keep their respective versions of the TLR procedure identical until a coordination procedure is in place. Therefore, the NERC staff is preparing a business practice request that will mimic the NERC SAR to incorporate the market flow term.

Item 4. SAR to Revise EOP-004, "Disturbance Reporting"

Action

Assign to NERC.

John Theotonio will be available to answer questions about the SAR.

Attachments

a. SAR to revise EOP-004 (**Item 4a**)

b. Draft standard EOP-004, "Disturbance Reporting" (markup) (**Item 4b**)

Background

This SAR is intended to update Attachment 2 of EOP-004 to include the latest U.S. Department of Energy disturbance reporting requirements.

The SAR and draft standard are both attached.

Item 5. R05004 TTC/ATC/AFC/CBM/TRM in Requesting and Scheduling Transmission Service

Action

Assign to NAESB.

Attachments

a. NAESB business practice request (final) (**Item 5a**)

b. NAESB business practice request (markup) (**Item 5b**)

Background

At the JIC's July 21-22, 2005 meeting, Barry Green presented a proposal of the NERC Long Term ATC/AFC Task Force (which no longer exists) to develop a business practice standard on processing transmission service requests, as related to TTC, ATC, AFC, CBM, and TRM. Here's the excerpt from the meeting minutes:

> Barry Green moved that the JIC assign R05004 to NAESB for development.
>
> Several questions were raised in discussion of the request:
>
> • Section 3 — Use of the term "evaluation" implies, or could be confused with, reliability evaluation that is performed by transmission operators and reliability coordinators to determine if the system is secure. A clarification would be to remove the term "evaluation" and use more specific language that explains the intended scope.
>
> • Section 4b — The phrase "ensuring consistent scheduling practices" appears to be too broad, possibly encompassing reliability aspects of transmission scheduling already addressed in existing standards. Omission of Section 4b appears to be an appropriate clarification that the scope of the request is as stated in Section 4a, focused on "processing requests for transmission service."
>
> • Section 7 — A number of the bullets listed within the scope appear to be reliability focused.
>
> Examples of language that could be revised to better clarify the intended scope include:
>
> - "Determine the quantity of transmission service to be made available."
> - "Use similar models and assumptions."

- "Use models and assumptions ... that are similar to those used for the planning of the transmission system."

Following the discussion, the JIC agreed by unanimous consent to request the motion be withdrawn and it was. NAESB will refer the request back to the requester for further clarifications regarding the intended scope. Barry Green, who is on the LTATF, will communicate the JIC's comments and questions to them.

The markup and final versions of the business practice request are attached; the drafting team removed the phrases that certain members of the JIC objected to.

Secretary's note: As with standards on interchange and transmission loading relief where the marketplace meets system operations, the ATC standards and business practices need close coordination. The most effective way to do this is for the NERC ATCT SAR drafting team to meet jointly with the group to which NAESB assigns the business practice development.

Item 6. TLR Coordination Procedure

Action

Discussion.

Background

At its November 29, 2005 meeting, the WEQ Executive Committee approved the business practices portion of the TLR procedure that the NAESB Business Practices Subcommittee had drafted. However, because:

1. The industry comments to both NERC and NAESB included a number of objections to dividing the TLR procedure into a separate reliability standard and business practice, and
2. The NERC Operating Reliability Subcommittee withdrew the SAR, not only because of the industry's objections, but also because there was no apparent way to keep the two parts of the TLR procedure coordinated in the future,

the Executive Committee decided to postpone ratifying the TLR business practice until the NAESB board agreed to an effective method for keeping the two parts of the TLR procedure coordinated.

Following that November 29 meeting, the NERC and NAESB staffs have been working on a procedure that will ensure that:

1. The reliability standards and business practice standards within the TLR Procedure will remain closely coordinated,
2. The complete TLR Procedure will be readily available to transmission system operators and reliability coordinators, and
3. The TLR Procedure will remain consistent with or superior to the Federal Energy Regulatory Commission pro forma tariff.

The first two points respond to many (if not most) of the criticisms that the industry submitted in comments to both NERC on its SAR and NAESB on its complementary business practice request to divide the TLR procedure between the two organizations.

The third point, though not raised in the industry comments, is important enough to keep front and center while we develop the coordination process.

At this time, the NERC and NAESB staffs are looking at different ways to coordinate the TLR procedure. We will discuss this with the JIC.

Item 7. Next Meeting

The JIC usually meets when necessary, and we should consider what SARs and business practice requests are coming down the pipeline.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

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

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

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

II. PROHIBITED ACTIVITIES

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

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.

- Discussions of a participant's marketing strategies.

- Discussions regarding how customers and geographical areas are to be divided among competitors.

- Discussions concerning the exclusion of competitors from markets.

- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

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

III. ACTIVITIES THAT ARE PERMITTED

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

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

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

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

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

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

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.

- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.

- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

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

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October 7, 2005

TO: NERC-NAESB-ISO/RTO Council Joint Interface Committee, and Interested Industry Participants

FROM: Laura B. Kennedy, Meeting/Project Manager

RE: Joint Interface Committee Conference Call Draft Minutes – October 5, 2005

NERC-NAESB-ISO/RTO Council Joint Interface Committee
Conference Call
October 5, 2005 – 2:00 pm to 4:00 pm Central
DRAFT MINUTES

1. Administrative Items

Ms. Campbell called the meeting to order and welcomed the participants. Mr. Benjamin called the roster of the Joint Interface Committee (JIC) members and a quorum was established. Ms. Kennedy read the antitrust guidelines. Mr. Schwerdt made a motion to adopt the minutes from the July 21-22, 2005 meeting as drafted. Mr. Jones seconded the motion. The motion passed unanimously. The minutes are posted on the NAESB website at: http://www.naesb.org/pdf2/weq_jic072105dm.pdf. The agenda was adopted by consensus.

2. Proposed Business Practice Standards

NAESB did not submit any Requests for Standards Development for consideration.

3. Proposed Reliability Standards

Standards Authorization Request: "Provide Missing Measures and Compliance Elements in Existing Standards"

NERC submitted one Standards Authorization Request (SAR) for consideration: "Provide Missing Measures and Compliance Elements in Existing Standards." This SAR is posted as part of the agenda and meeting materials on the NAESB website at: http://www.naesb.org/pdf2/weq_jic100505a.pdf.

Ms. Campbell stated that the NERC Compliance and Certification Managers Committee (CCMC) reviewed the existing reliability standards approved as Version 0 and identified that a number of the standards were missing measures and compliance elements. The CCMC drafted a SAR to revise the standards to include the missing elements and to include the standards in the Compliance Monitoring Program. The CCMC developed a plan for implementation of the revisions in stages. The first set would be revised in 2005 and implemented in 2006; the second set would be revised in 2006 and implemented in 2007; the third set would be revised in 2007 and implemented in 2008; and the fourth set would be revised in 2008 and implemented in 2009. The scope of the SAR was modified and the priority of the implementation was revised as a result of industry comments.

Mr. Yeager asked if a new Standards Authorization Request would be submitted if the Drafting Team for this SAR determined that the requirements are not significantly clear and concise. Ms. Campbell stated that it was her understanding that the Drafting Team for this SAR would limit its work to the missing elements and measures. If the Drafting Team determines that the requirements should be modified, it will submit a new Standards Authorization Request. Mr. Lucas asked if this SAR would result in a need for the NAESB Wholesale Electric Quadrant to modify existing business practice standards. Mr. Schwerdt stated that work on this SAR should not result in new reliability requirements or new business practice requirements.

Mr. Fidrych moved to send the Provide Missing Measures and Compliance Elements in Existing Standards SAR to NERC for development. Mr. Hughes seconded the motion. The motion passed unanimously.

4. Other Business

a. Expected Standards Authorization and Business Practices Requests

Mr. Benjamin asked if participants knew of SARs and Business Practice Standards Requests that would be submitted for review by the JIC before the end of the year. Mr. Henry stated that the best way to determine the status of NERC SARS is to consult the Standards Development page of the NERC website. Ms. McQuade stated that NAESB Requests that are assigned to the Wholesale Electric Quadrant by the Triage Committee are presented to the JIC. A few new Requests for Standards Development have been assigned to the Wholesale Electric Quadrant that will require a more detailed scope before they are presented to the JIC. Mr. Benjamin stated he would consult with Mr. Ladrow to keep abreast of NERC SAR development and would consult with the NAESB Triage Committee page to keep abreast of NAESB Request development.

b. Future Meetings and Conference Calls

Mr. Benjamin, Ms. McQuade, and Ms. Campbell will work to circulate potential meeting dates in January 2006 for a JIC meeting at FRCC's offices in Tampa, Florida to review the NERC 2006 Annual Plan and the NAESB Wholesale Electric Quadrant Annual Plan.

c. Other Business

Mr. Henry stated that the NERC TLR SAR Drafting Team reported to the NERC Standards Authorization Committee that a number of comments have been filed indicating that the industry believes NERC and NAESB should review the split of the reliability components and business practice components of TLR. The NERC Standards Authorization Committee thought that the JIC should consider reconvening the Joint TLR Group.

Ms. McQuade stated that the NAESB Wholesale Electric Quadrant (WEQ) Business Practices Subcommittee (BPS) is scheduled to post the draft TLR recommendation for the thirty day industry comment period next week, and therefore NAESB has not yet received any comments on the split of the reliability components and business practice components of the TLR standards. Mr. Henry suggested that the JIC encourage the NERC TLR SAR Drafting Team and the NAESB WEQ BPS to closely coordinate the TLR standards drafting process. Ms. McQuade stated that once the thirty day industry comment period expires, the NAESB Wholesale Electric Quadrant BPS and the NERC TLR SAR Drafting Team could meet jointly to review the comments submitted to NAESB and the comments submitted to NERC. For the comments to be considered part of the formal record in NAESB's process, concerned parties should be encouraged to participate in NAESB's process. The NERC comments will not be part of the formal record forwarded to FERC as part of NAESB's TLR effort. The joint group may choose prepare a report as part of the comment period that would be submitted to the NAESB WEQ Executive Committee in addition to the original BPS recommendation and the industry comments. If the report is endorsed by the group, it would follow the processes defined for NAESB and for NERC separately. The Executive Committee would then review the recommendations and comments before it votes to adopt the recommendation from the BPS. The report would also be submitted to NERC to be considered in the NERC process.

Mr. Henry moved that the JIC encourage NERC and NAESB to have their respective drafting teams jointly review the comments they receive as they proceed through their prospective standards development processes. The motion was seconded by Mr. Yeager. The motion passed unanimously.

Mr. Benjamin will ensure that the NERC TLR SAR Drafting Team is aware of the JIC's discussion and motion for the need for coordination among NERC and NAESB to complete the TLR recommendations. Ms. McQuade and Mr. Oberski will ensure that the NAESB WEQ BPS is also aware of the JIC's discussion and motion.

Ms. Szot stated that Mr. Phillips will replace Mr. Tammar as JIC IRC co-chair. Ms. Campbell stated that IRC representatives should ensure that the JIC IRC member roster is updated and forwarded to NERC and NAESB.

Mr. Lucas asked the JIC members if they anticipate that the role of the JIC would change once the ERO is established. Ms. Campbell stated that she did not anticipate the role of the JIC to change because NERC would still be developing reliability standards and NAESB would still be developing business practice standards for the industry.

5. Adjourn

The meeting adjourned at 3:05 PM Central.

6. JIC Member Attendance

NERC	
Linda Campbell (JIC Co-Chairman)	Florida Reliability Coordinating Council
Scott Henry	Duke Power
Sam Jones	ERCOT ISO
Ed Schwerdt	Northeast Power Coordinating Council
Mike Penstone	Hydro One
Mark Fidrych	Western Area Power Administration

NAESB	
Lou Oberski	Dominion Resources
Ed Davis	Entergy Services, Inc.
Walt Yeager	Cinergy Services, Inc.
Syd Berwager	Bonneville Power Administration
Mike Gildea	Constellation Generation Group
Roy True	ACES Power Marketing
John Lucas	Southern Company
John Hughes	Electricity Consumers Resource Council

ISO/RTO Council (IRC)	
Kent Saathoff	ERCOT
Lisa Szot	CAISO
Diana Pommen	AESO

7. Other Attendees

LaRita Cormier	Riverside Reporting

Don Benjamin	NERC
Laura Kennedy	NAESB
Larry Kezele	NERC
Bill Lohrman	NERC
Rae McQuade	NAESB
Herb Schrayshuen	National Grid Transmission USA

North American Energy Standards Board and North American Electric Reliability Council Joint Interface Committee (JIC) Members

prepared January 6, 2006

North American Electric Reliability Council (NERC)					
Linda Campbell	Director of Reliability	Florida Reliability Coordinating Council	NERC Standards Authorization Committee (SAC) Chair	lcampbell@frcc.com	813-289-5644
Scott Henry	Director, Regulatory Policy	Duke Power	NERC SAC member	rshenry@duke-energy.com	704-382-6182
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Don Benjamin	Vice President, Operations	NERC	JIC Secretary	don.benjamin@nerc.net	609-452-8060
North American Energy Standards Board (NAESB)					
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North American Energy Standards Board (NAESB) - Alternates					
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			ISO/RTO Council (IRC)		
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NORTH AMERICAN ENERGY STANDARDS BOARD
2006 WEQ Annual Plan
Approved by the Board of Directors – 12-13-05

	Item Description	Completion[1]	Assignment[2]
1	**Develop business practices standards as needed to complement reliability standards**		
	Develop business practice standards to support and complement NERC reliability standards, NERC policies and NERC standards authorization requests (SARs). Current NAESB activities underway to develop business practice standards that are supportive of this annual plan item are:		
	a) Make version 1 changes to business practices as requested.	Ongoing	BPS
	i) Make changes to business practices as related to inclusion of functional model entities as NERC undertakes the same efforts	As requested	BPS
	ii) Review the NAESB WEQ “Version 0” business practice standards and remove any references to ERCOT (R05007)	1st Q, 2006	BPS
	b) Develop business practices to support Coordinate Interchange – update already adopted version 1 to reflect version 1 NERC CI (R03013, R05001, R05020)	3rd Q, 2006	BPS
	c) Develop business practice standards to support Operate Within Limits (R03017)	2006	BPS
	d) Develop business practices to support the reliability components of TLR		
	i) Version 0 Split of TLR business practices from reliability components	1st Q, 2006	BPS
	ii) Continuous support of TLR Procedure in alignment with NERC efforts including version 1 development	Ongoing	BPS
	f) Determine any needed NAESB action in support of the Interchange Distribution Calculator (IDC).	2006	BPS
	g) Develop jointly with NERC a Joint NERC/NAESB Operating training manual.	2006	BPS
2	**Develop business practice standards for Version 1 to support ATC calculations**		
	Develop version 1 business practice standards to better coordinate the use of the transmission system among neighboring transmission providers. Such business practice standards would be based on recommendations from NERC's Long Term ATC/AFC Task Force and would involve revised procedures for the ATC calculation and/or revised protocols for coordination between neighboring transmission providers and/or amendments to existing TLR procedures.	Pending	BPS
	Note: Awaiting revised clarified Request R05004 from NERC – to develop transmission service request and scheduling standards using TTC/ATC/AFC and CBM/TRM.		
3	**Develop business practices standards to improve the current operation of the wholesale electric market and develop and maintain business practice and communication standards for OASIS and Electronic Scheduling**		
	a) Develop and/or maintain business practice standards as needed for OASIS and electronic scheduling. Specific items to		

NORTH AMERICAN ENERGY STANDARDS BOARD
2006 WEQ Annual Plan
Approved by the Board of Directors – 12-13-05

Item Description		Completion[1]	Assignment[2]
	address include:		
i)	Business Practices for the resale or reassignment of transmission service (R04006D)	1st Q, 2006	ESS/ITS
ii)	Implementation of "release" mechanism in the OASIS S&CP to complement non-firm redirects (R04006C1)	1st Q, 2006	ESS/ITS
iii)	Network Services: determine if business practice standards or other support is needed to support use of OASIS for Network Service transactions (R04006E).	3rd Q, 2006	JISWG
iv)	Registry: determine if business practice standards are needed to support the registry functions currently supported by NERC (R04037).	2nd Q, 2006	JISWG
v)	Adoption/maintenance of ESC use cases (R04007)	1st Q, 2006	ESS/ITS
vi)	Adoption/maintenance of Functional Requirements Document (R04007)	1st Q, 2006	ESS/ITS
vii)	e-Tag enhancements (including e-Tag specification changes) (R05018)	2nd Q, 2006	ESS/ITS
viii)	Document procedures used to implement the displacement/interruption terms of the Pro Forma tariff (R05019)	3rd Q, 2006	ESS/ITS
ix)	Incremental enhancements to OASIS as an outgrowth of the NAESB March 29, 2005 conference on the future of OASIS (R05026)	TBD	Not Assigned
b)	Develop and/or maintain standard communication protocols and cyber-security business practices as needed		
i)	Develop companion business practices to NERC's Cyber Standard (CIP002-009), and specifically review section 1303-Personnel & Training to determine if business practices are needed.	3rd Q, 2006	ESS/ITS
ii)	Partner with the Department of Energy to perform a surety assessment on NAESB technical standards and respond to the surety assessment findings and recommendations.	4th Q, 2006	EC Officers
iii)	PKI Initiative (e-MARC) (R03007)	1st Q, 2006	JISWG
c)	Develop business practices as needed for clarification of definitions and terminology in the Standards of Conduct[3]	1st Q, 2006	BPS
d)	Develop needed business practice standards for organization/company codes for NAESB standards – and address current issues on the use of DUNs numbers.	4th Q, 2006	Not Assigned

PROVISIONAL ITEMS

1 Develop business practice standards as requested by the regional and state advisory groups.

2 Using the NERC Interconnected Operations Services reference document (March 2002, version 1.1) as a guide and starting

	Item Description	Completion[1]	Assignment[2]
	point, develop business practices as necessary for ancillary services and/or interconnected operating services transactions.		
3	Develop and or modify business practices related to OATT reform resulting from the Notice of Inquiry, Docket No. RM05-25-000, FERC Notice Requesting Comments, "Preventing Undue Discrimination and Preference in Transmission Services", issued September 16, 2005.		
4	Evaluate the entries on the seams catalog, determine the need for business practice standards and draft the standards requests to develop business practice standards to complement or assist specific seams mitigation efforts as noted in the seams catalog.		
5	Develop business practice standards according to approved and assigned standards requests that complement or assist specific seams mitigation efforts as noted in the seams catalog.		
6	Develop business practice standards as related to the Effectiveness Study of Competitive Wholesale Markets (Congressional Mandate), Electric Energy Market Competition Task Force, Docket No. AD05-17-000, issued by the FERC on October 13, 2005.		
7	Upon the issuance of the final order by FERC, develop and or modify business practices as requested by FERC related to OASIS or Version 0 business practices as filed by NAESB with the FERC on January 18, 2005, in Docket No. RM05-5-000. The FERC Notice of Proposed Rulemaking, RM05-5-000, "Standards for Business Practices and Communication Protocols for Public Utilities," was issued May 9, 2005.		
8	Develop and/or maintain business practice standards to support gas-electric interdependencies • Respond to requests as received that are related to Docket No. RM05-28-000. • Respond directives related to the conclusions of the NAESB reports submitted in Docket No. RM05-28-000. • Evaluate and develop business practice standards for Energy Day (R04016). • Evaluate and develop business practice standards for electric scheduling timelines (R04020).		

North American Energy Standards Board
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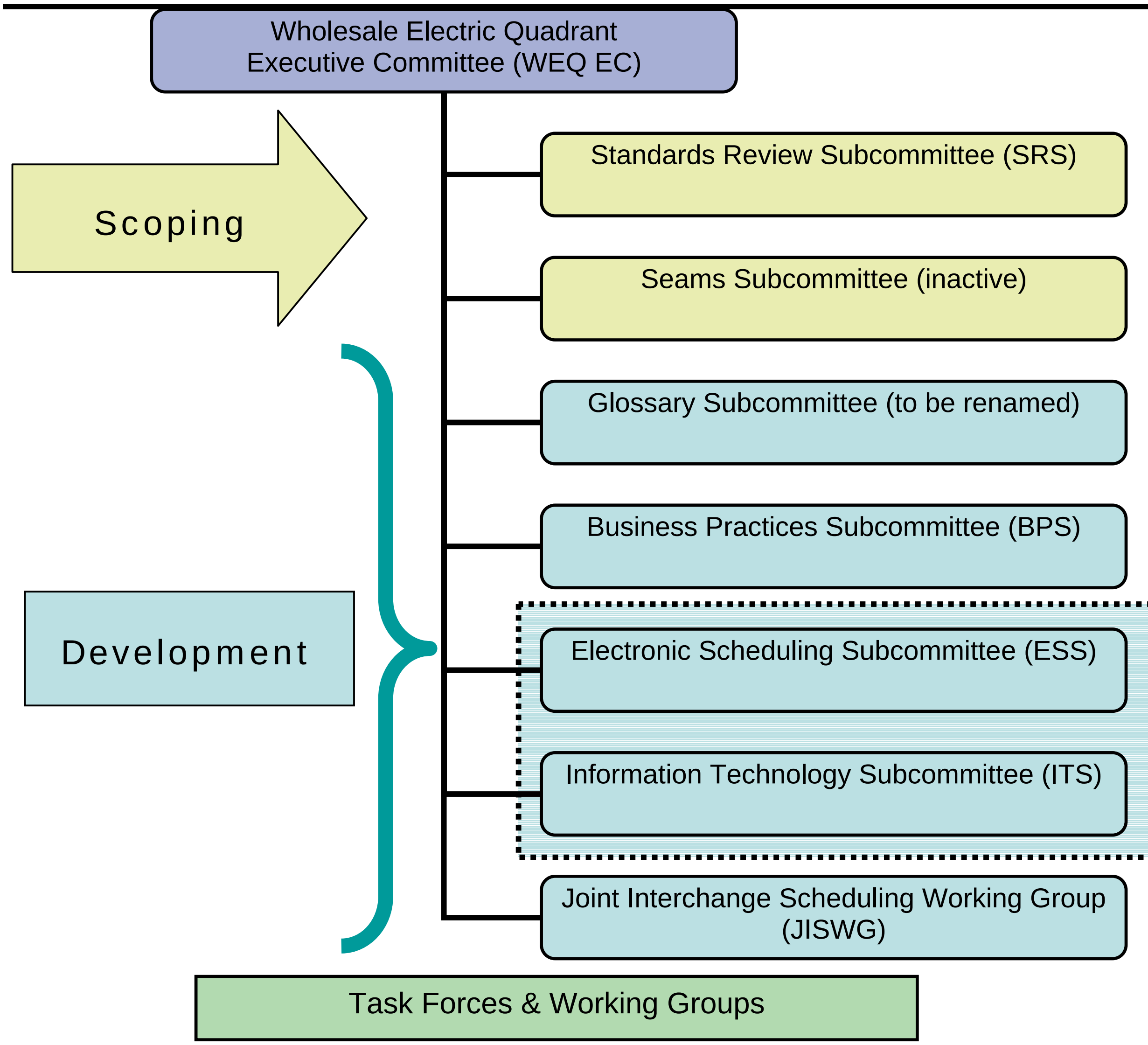


NAESB WEQ EC and Subcommittee Leadership:

Executive Committee: Lou Oberski (WEQ EC Chair) and Tony Reed (WEQ EC Vice Chair)

Standards Review Subcommittee: Raj Rana, Narinder Saini, Ollie Frazier

Seams Subcommittee: Inactive

Business Practices Subcommittee & Task Forces: Kathy York & Joel Dison

Electronic Scheduling Subcommittee/Information Technology Subcommittee & Task Forces: Paul Sorenson, J.T. Wood and Sherri Monteith

- Coordinate Interchange: Roman Carter
- OASIS: J.T. Wood and Wendy Weathers

Joint Interchange Scheduling Working Group (JISWG): Bob Harshbarger

Glossary Subcommittee (to be renamed): Sherri Monteith

End Notes:

[1] Dates in the completion column are by end of the quarter for completion by the assigned committee. The dates do not necessarily mean that the standards are fully staffed so as to be implementable by the industry, and/or ratified by membership. If one item is completed earlier than planned, another item can begin earlier and possibly complete earlier than planned. There are no begin dates on the plan.
[2] The assignments are abbreviated. The abbreviations and committee structure can be found at the end of the annual plan document.
[3] The changes to the Standards of Conduct requested by the Commission in NOPR Docket No. RM05-5-000 will be made as soon as possible.

Item 2b

2006 Annual Work Plan
ISO/RTO COUNCIL

The ISO/RTO Council's 2006 Work Plan includes efforts by its Standards Review Committee ("SRC"), who will participate in industry standards development efforts with NERC, NAESB, and other organizations, as mandated by its Charter. It also includes efforts by its Information Technology Committee ("ITC") to develop methodologies for standardizing their intra- and inter-ISO/RTO protocols.

NERC Reliability Standards Development

ISO/RTOs will participate in the development and prepare consensus comments and positions, as appropriate, for Reliability standards that NERC plans to have developed during 2006. The actual schedule of standards is to be determined by NERC, and the following topics have been identified as high priority items in their 2006 Business Plan.

Complete these 2005 initiatives which may extend into 2006:

- Replacement standards for the Phase III-IV Planning Standards
- Permanent cyber security standards to replace the interim urgent action standard
- Comprehensive standards on transmission right-of-way vegetation management
- Three organization certification standards: Balancing Authority, Transmission Operator, and Reliability Coordinator
- Complete remaining compliance administration elements in Version 0 standards
- Coordinate Operations
- Determine Facilities Ratings, System Limits, and Transfer Capabilities
- Jointly with NAESB, develop reliability and business practice standards to replace the Transmission Loading Relief (TLR) Procedure

Development of these standards are underway and the SRC will track them in 2006:

- Operate Within Interconnection Reliability Operating Limits (IROL)
- Balance Resources and Demand
- System Personnel Training
- Resource Adequacy
- Nuclear Offsite Power Supply
- Coordinate Interchange
- Frequency Response
- ATC/TTC
- CBM/TRM

Development of these standards is likely to begin in 2006:

- Operating Tools
- Operating Reserves
- Reactive Reserves and Voltage Control in the Operating Horizon
- Begin Enhancing Version 0 Reliability Standards (including compliance elements)

- Voltage and Reactive Planning
- System Protection and Control
- System Modeling and Data Exchange
- Fuel Infrastructure Reliability
- Analysis of Fuel Infrastructure Contingencies

In addition, the SRC will comment on any adjustments proposed to NERC's Functional Model, and will continue to review the FERC ERO rulemaking and resulting NERC application to be certified as the ERO.

Business Standards Development Activities with NAESB

The SRC will follow NAESB's development of business standards by providing the perspectives and expertise of subject matter experts, as appropriate. The SRC will track the work and ISO/RTO representation with the NAESB WEQ's Subcommittees, Task Forces, and working groups. The SRC, in collaboration with the other IRC committees, will advise NAESB on issues identified, submit comments in the standards process, and provide joint responses to NAESB.

NAESB anticipates that it will address the following areas in 2006 to develop business practices which supplement NERC's reliability standards:

- Make version 1 changes to business practices as requested.
- Develop Inadvertent Interchange Payback, Coordinate Interchange, Operate within Limits Business Practices
- Develop business practices to support the reliability components of TLR
- Determine any needed NAESB action in support of the Interchange Distribution Calculator (IDC).
- Develop jointly with NERC a Joint NERC/NAESB Operating training manual.
- Develop business practice standards for Version 1 to support ATC calculations
- Develop business practices standards to improve the current operation of the wholesale electric market and develop and maintain business practice and communication standards for OASIS and Electronic Scheduling
    - Clarification of definitions and terminology in OASIS Business Practices
    - Business Practices for the resale or reassignment of transmission service
    - Implementation of "release" mechanism in the OASIS S&CP to complement non-firm redirects
    - Network Services: determine if business practice standards or other support is needed to support use of OASIS for Network Service transactions.

    - Registry: determine if business practice standards are needed to support the registry functions currently supported by NERC.
    - Adoption/maintenance of ESC use cases
    - Adoption/maintenance of Functional Requirements Document
- Cyber-security initiatives:
    - PKI Initiative (e-MARC)
    - e-Tag enhancements (including e-Tag specification changes)
    - Develop and/or maintain standard communication protocols and cyber-security requirements as needed, including related industry standard communication protocols and cyber-security requirements
    - Develop companion business practices to NERC's Cyber Standard (1300), and specifically review section 1303-Personnel & Training to determine if business practices are needed.
- Develop business practices as needed for clarification of definitions and terminology in the Standards of Conduct
- Develop needed business practice standards for organization/company codes for NAESB standards – and address current issues on the use of DUNs numbers

Coordination with NAESB and NERC

The SRC will advise the IRC's JIC representatives on issues so the Council can effectively work jointly with NAESB and NERC to coordinate standards development and related work efforts of each organization.

ITC Initiatives

The following ITC initiatives are aimed at improving the ability of ISO/RTO organizations to standardize, where appropriate, their methodologies for certain tools used by their respective system operators and IT organizations. These initiatives are in the general areas of operational communications, data standardization, web services and operator visualization techniques.

- Complete development of a visualization framework to support the deployment of standard visualization capabilities in power system operations control centers and allow individual ISO/RTOs to determine how and when implementation projects would be started.
- Complete consistent methodologies for web services that reduce implementation costs and improve inter-operability, and use actual ISO/RTO projects to test and refine.
- Confirm inter-system interfaces and allow future ISO needs-driven projects to refine interface payloads into consistent methodologies as required.

- Complete Central Alarm Management initiative as a flexible means to manage control room and business exception conditions.
- Complete Security Constrained Unit Commitment comparator.

When completed, e-mail to: mark.ladrow@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Modification to IRO-006-1 to allow Market Flow Information as input to IDC
Request Date	12/15/05

SAR Requestor Information	**SAR Type** (Check box for one of these selections.)	
Name Lanny Nickell	☐	New Standard
Primary Contact same	☒	Revision to existing Standard
Telephone 501.614.3232 Fax	☐	Withdrawal of existing Standard
E-mail lnickell@spp.org	☐	Urgent Action

Purpose (Describe the purpose of the proposed standard — what the standard will achieve in support of reliability.)

Industry Need (**Provide** a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

SPP is requesting a modification to the NERC Transmission Loading Relief (TLR) procedure to expand the scope of values accepted by the Interchange Distribution Calculator (IDC) to include Market Flows. Market Flows represent the impacts on flowgates of energy dispatched in a market, such as that operated by a Regional Transmission Organization or Independent System Operator, that are not tagged as an interchange transactions. Allowing Market Flow impacts to be represented in the IDC allows markets to participate in the Eastern Interconnection transmission loading relief method on a basis equivalent to that of tagged interchange transactions. The reliability benefit is that these market resources then are able to participate in the reduction of flows on a specified flowgate during a transmission loading relief event. The proposed change is similar to and replaces the regional differences that currently exist for MISO and PJM. The proposed revision to the standard has been endorsed by the NERC Operating Reliability Subcommittee. The proposed revision, if approved, will replace the waivers for PJM and MISO that were carried over in the Version 0 standards. The changes to the standard will be applicable to any market entity and will therefore remove the presence of a regional difference from the standard.

Reliability Functions

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

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. 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 a Standard based on this description.)

NNL Calculations

Attachment 1-IRO-006-1, Section 5 (Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service)

Section 5 of Attachment 1-IRO-006-1 currently 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 control area.

SPP intends to use a "Market Flow Calculation" methodology to calculate the portion of parallel flows on all facilities included in the RTO's "Coordinated Flowgate List" due to NI service or service to NL of each control area.

Pro Rata Curtailment of Non-Firm Market Flow Impacts

Attachment 1-IRO-006-001, Appendix B (Transaction Curtailment Formula)

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

Assignment of Sub-Priorities

- Attachment 1-IRO-006-1, Appendix E (How the IDC Handles Reallocation), Section E2 (Timing Requirements)

Under the header "IDC Calculations and Reporting" in Section E2 of Appendix E to Attachment 1-IRO-006-001, 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.

SPP intends to use a "Market Flow Calculation" methodology to calculate the amount of energy flowing across all facilities included in the RTO's "Coordinated Flowgate List" that is associated with the operation of the RTO market. This energy is identified as "market flow".

These market flow impacts for current hour and next hour will be separated into their appropriate priorities 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, SPP proposes that for the purposes of reallocation, a sub-priority (S1 thru S3) 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. Since SPP market flow is always present, sub-priority 4 is not applicable.

ADDITIONAL DETAIL is INCLUDED in ATTACHED DOCUMENT

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation
None Assigned	A TLR Modifications SAR is currently being developed in parallel by a joint NERC and NAESB committee. Their efforts are aimed at both updating the procedure and then subdividing the standard into reliability requirements and business practices. Modifications need to be coordinated, but the modifications needed to implement the SPP market changes need to be accomplished by May 1, 2006 to meet the schedule submitted to FERC.

Regional Differences

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

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. SAC approves SAR for posting (September 29, 2005).
2. Requestor posts Draft SAR for comment (October 6-November 7, 2005)
3. SAC accepts SAR for development as a standard (Anticipated January 8, 2006)

Description of Current Draft:

This is the first draft of the standard to be posted for a 45-day stakeholder comment period (January 1–February 15, 2006) along with the associated implementation plan.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments from stakeholder posting on Standards and Implementation Plan.	February 21, 2006
2. Post for 30-day pre-ballot period.	March 1–March 30, 2006
3. Conduct ballot.	April 3–12, 2006
4. Post response to comments on 1st ballot	April 17, 2006
5. Conduct 2nd ballot	April 21–30, 2006
6. Post for 30-day period prior to board adoption.	April 1–30, 2006
7. Board adoption and effective date.	May 1, 2006

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 flow on a Flowgate generated by a Balancing Authority's generation to load dispatch; equal to the sum of Firm and Non-firm (economic) flows.

Curtailment: A reduction in power flow over the given facilities by reducing Interchange Transactions or Market Flows.

A. Introduction

1. **Title:** **Reliability Coordination — Transmission Loading Relief**

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

3. **Purpose:** Regardless of the process it uses, the Reliability Coordinator must direct its Balancing Authorities and Transmission Operators to return the transmission system to within its Interconnection Reliability Operating Limits as soon as possible, but no longer than 30 minutes. The Reliability Coordinator needs to direct Balancing Authorities and Transmission Operators to execute actions such as reconfiguration, redispatch, or load shedding until relief requested by the TLR process is achieved.

4. **Applicability**

   4.1. Reliability Coordinators.

   4.2. Transmission Operators.

   4.3. Balancing Authorities.

5. **Effective Date:** ~~August 8, 2005~~May 1, 2006

B. Requirements

R1. A Reliability Coordinator shall take appropriate actions in accordance with established policies, procedures, authority, and expectations to relieve transmission loading.

R2. A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, at its discretion, select from either a “local” (Regional, Interregional, or subregional) transmission loading relief procedure or an Interconnection-wide procedure.

R2.1. The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection is provided in Attachment 1-IRO-006-~~0~~.

R2.2. The equivalent Interconnection-wide transmission loading relief procedure for use in the Western Interconnection is the “WSCC Unscheduled Flow Mitigation Plan,” provided at: http://www.wecc.biz/documents/library/UFAS/UFAS_mitigation_plan_rev_2001-clean_8-8-03.pdf.

R2.3. The Interconnection-wide transmission loading relief procedure for use in ERCOT is provided as Section 7 of the ERCOT Protocols, posted at: http://www.ercot.com/tac/retailisoadhoccommittee/protocols/keydocs/draftercotprotocols.htm.

R3. The Reliability Coordinator may use local transmission loading relief or congestion management procedures, provided the Transmission Operator experiencing the potential or actual SOL or IROL violation is a party to those procedures.

R4. A Reliability Coordinator may implement a local transmission loading relief or congestion management procedure simultaneously with an Interconnection-wide procedure. However, the Reliability Coordinator shall follow the curtailments as directed by the Interconnection-wide procedure. A Reliability Coordinator desiring to use a local procedure as a substitute for curtailments as directed by the Interconnection-wide procedure shall have such use approved by the NERC Operating Committee.

R5. When implemented, all Reliability Coordinators shall comply with the provisions of the Interconnection-wide procedure including, for example, action by Reliability Coordinators in other Interconnections to curtail an Interchange Transaction that crosses an Interconnection boundary.

R6. During the implementation of relief procedures, and up to the point that emergency action is necessary, Reliability Coordinators and Balancing Authorities shall comply with interchange scheduling standards INT-001 through INT-004.

C. Measures

M1. If required, an investigation will be conducted to determine whether appropriate actions were taken in accordance with established policies, procedures, authority, and expectations to relieve transmission loading, including notifying appropriate Reliability Coordinators and operating entities to curtail Interchange Transactions.

D. Compliance

1. Compliance Monitoring Process

The Regional Reliability Organization or NERC may initiate an investigation if there is a complaint that an entity has not implemented relief procedures in accordance with these requirements.

1.1. Compliance Monitoring Responsibility

Not specified.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance Monitoring Period: One calendar year.

Reset Period: One month without a violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: The Reliability Coordinator did not implement loading relief procedures in accordance with the standard.

E. Regional Differences

PJM/MISO Enhanced Congestion Management (Curtailment/Reload/Reallocation) Waiver approved March 25, 2004.

Version History

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

0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 8, 2005	Revised Attachment 1	Revision

Attachment 1-IRO-006-~~1~~2

Transmission Loading Relief Procedure — Eastern Interconnection

Purpose

This standard defines procedures for curtailment and reloading of Interchange Transactions and Market Flows to relieve overloads on transmission facilities modeled in the Interchange Distribution Calculator. This process is defined in the requirements below, and is depicted in Appendix A. Examples of curtailment calculations using these procedures are contained in Appendix B.

Applicability

This standard only applies to the Eastern Interconnection.

1. Transmission Loading Relief (TLR) Procedure

1.1. Initiation only by Reliability Coordinator. A Reliability Coordinator shall be the only entity authorized to initiate the TLR Procedure and shall do so at 1) the Reliability Coordinator's own request, or 2) upon the request of a Transmission Operator.

1.2. Mitigating transmission constraints. A Reliability Coordinator may utilize the TLR Procedure to mitigate potential or actual System Operating Limit (SOL) violations or Interconnection Reliability Operating Limit (IROL) violations on any transmission facility modeled in the IDC.

1.2.1. Requesting relief on tie facilities. Any Transmission Operator who operates the tie facility shall be allowed to request relief from its Reliability Coordinator.

1.2.1.1. Interchange Transaction priority on tie facilities. The priority of the Interchange Transaction(s) to be curtailed shall be determined by the Transmission Service reserved on the Transmission Service Provider's system who requested the relief.

1.3. Order of TLR Levels and taking emergency action. The Reliability Coordinator shall not be required to follow the TLR Levels in their numerical order (Section 2, "TLR Levels"). Furthermore, if a Reliability Coordinator deems that a transmission loading condition could jeopardize Bulk Electric System reliability, the Reliability Coordinator shall have the authority to enter TLR Level 6 directly, and immediately direct the Balancing Authorities or Transmission Operators to take such actions as redispatching generation, or reconfiguring transmission, or reducing load to mitigate the critical condition until Interchange Transactions and Market Flows can be reduced utilizing the TLR Procedure or other methods to return the system to a secure state.

1.4. Notification of TLR Procedure implementation. The Reliability Coordinator initiating the use of the TLR Procedure shall notify other Reliability Coordinators and Balancing Authorities and Transmission Operators, and must post the initiation and progress of the TLR event on the appropriate NERC Web page(s).

1.4.1. Notifying other Reliability Coordinators. The Reliability Coordinator initiating the TLR Procedure shall inform all other Reliability Coordinators via the Reliability Coordinator Information System (RCIS) that the TLR Procedure has been implemented.

1.4.1.1. Actions expected. The Reliability Coordinator initiating the TLR Procedure shall indicate the actions expected to be taken by other Reliability Coordinators.

1.4.2. Notifying Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify Transmission Operators and Balancing Authorities in its Reliability Area when entering and leaving any TLR level.

1.4.3. Notifying Balancing Authorities. The Reliability Coordinator for the sink Balancing Authority shall be responsible for directing the Sink Balancing Authority to curtail the Interchange Transactions as specified by the Reliability Coordinator implementing the TLR Procedure.

1.4.3.1. Notification order. Within a Transmission Service Priority level, the Sink Balancing Authorities whose Interchange Transactions have the largest impact on the Constrained Facilities shall be notified first if practicable.

1.4.4. Updates. At least once each hour, or when conditions change, the Reliability Coordinator implementing the TLR Procedure shall update all other Reliability Coordinators (via the RCIS). Transmission Operators and Balancing Authorities who have had Interchange Transactions or Market Flows impacted by the TLR will be updated by their Reliability Coordinator.

1.5. Obligations. All Reliability Coordinators shall comply with the request of the Reliability Coordinator who initiated the TLR Procedure, unless the initiating Reliability Coordinator agrees otherwise.

1.5.1. Use of TLR Procedure with "local" procedures. A Reliability Coordinator shall be allowed to implement a local transmission loading relief or congestion management procedure simultaneously with an Interconnection-wide procedure. However, the Reliability Coordinator shall be obligated to follow the curtailments as directed by the Interconnection-wide procedure. If the Reliability Coordinator desires to use a local procedure as a substitute for Curtailments as directed by the Interconnection-wide procedure, it may do so only if such use is approved by the NERC Operating Committee.

1.6. Consideration of Interchange Transactions. The administration of the TLR Procedure shall be guided by information obtained from the IDC.

1.6.1. Interchange Transactions not in the IDC. Reliability Coordinators shall also treat known Interchange Transactions that may not appear in the IDC in accordance with the procedures in this document.

1.6.2. Transmission elements not in IDC. When a Reliability Coordinator is faced with an overload on a transmission element that is not modeled in the IDC, the Reliability Coordinator shall use the best information available to curtail Interchange Transactions and Market Flows in order to operate the system in a reliable manner. The Reliability Coordinator shall use its best efforts to ensure that Interchange Transactions with a Transfer Distribution Factor of less than the Curtailment Threshold on the transmission element not modeled in the IDC are not curtailed.

1.6.3. Questionable IDC results. Any Reliability Coordinator (or Transmission Operator through its Reliability Coordinator) who believes the curtailment list from the IDC for a particular TLR event is incorrect shall use its best efforts to communicate those adjustments necessary to bring the curtailment list into conformance with the principles of this Procedure to the initiating Reliability Coordinator. Causes of questionable IDC results may include:

- Missing Interchange Transactions that are known to contribute to the Constraint.
- Significant change in transmission system topology.
- TDF matrix error.

Impacts of questionable IDC results may include:

- Curtailment that would have no effect on, or aggravate the constraint.
- Curtailment that would initiate a constraint elsewhere.

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

1.6.4. Curtailment that would cause a constraint elsewhere. A Reliability Coordinator shall be allowed to exempt an Interchange Transaction or Market Flow from Curtailment if that Reliability Coordinator is aware that the Interchange Transaction Curtailment directed by the IDC would cause a constraint to occur elsewhere. This exemption shall only be allowed after the Reliability Coordinator has consulted with the Reliability Coordinator who initiated the Curtailment.

1.6.5. Redispatch options. The Reliability Coordinator shall ensure that Interchange Transactions and Market Flows that are linked to redispatch options are protected from Curtailment in accordance with the redispatch provisions.

1.6.6. Reallocation. The Reliability Coordinator shall consider for Reallocation Market Flows and any Transactions of higher priority that meet the approved tag submission deadline during a TLR Level 3A. The Reliability Coordinator shall consider for Reallocation Market Flow and any Transaction using Firm Transmission Service that has met the approved tag submission deadline during a TLR Level 5A. Note Reallocations for Dynamic Schedules are as follows: If an Interchange Transaction is identified as a Dynamic Schedule and the transmission service is considered firm according to the constrained path method, then it will not be held by the IDC during TLR level 4 or lower. Adjustments to Dynamic Schedules in accordance with INT-004 R5 will not be held under TLR level 4 or lower.

1.7 IDC updates. Any Interchange Transaction or Market Flow adjustments or curtailments that result from using this Procedure must be entered into the IDC.

1.8 Logging. The Reliability Coordinator shall complete the NERC Transmission Loading Relief Procedure Log whenever it invokes TLR Level 2 or above, and send a copy of the log via email to NERC within two business days of the TLR event for posting on the NERC website.

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

1.9.1. Providing information. Transmission Operators and Balancing Authorities within the Reliability Coordinator's Area, and all other Reliability Coordinators, including Transmission Operators and Balancing Authorities within their respective Reliability Areas, shall provide information, as requested by the initiating Reliability Coordinator, in accordance with TLR review processes established by NERC.

1.9.2. Market Committee reviews. The Market Committee may conduct reviews of certain TLR events based on the size and number of Interchange Transactions or Market Flows that are affected, the frequency that the TLR Procedure is called for a particular Constrained Facility, or other factors.

1.9.3. Operating Reliability Subcommittee reviews. The Operating Reliability Subcommittee shall conduct reviews to ensure proper implementation and for "lessons learned."

2. Transmission Loading Relief (TLR) Levels

Introduction

This section describes the various levels of the TLR Procedure. The description of each level begins with the circumstances that define the TLR Level, followed by the procedures to be followed.

The decision that a Reliability Coordinator makes in selecting a particular TLR Level often depends on the transmission loading condition and whether the Interchange Transaction is using Non-firm Point-to-Point Transmission Service or Firm Point-to-Point Transmission Service or whether the Market Flow is firm or non-firm. There are further considerations that depend on whether the Constrained Facility is on or off the Contract Path. It is important to note that an Interchange Transaction using Firm Point-to-Point Transmission Service on all Contract Path links is considered a "firm" Interchange Transaction even if the Constrained Facility is off the Contract Path.

2.1. TLR Level 1 — Notify Reliability Coordinators of potential SOL or IROL Violations

2.1.1. The Reliability Coordinator shall use the following circumstances to establish the need for TLR Level 1**:**

- The transmission system is secure.
- The Reliability Coordinator foresees a transmission or generation contingency or other operating problem within its Reliability Area that could cause one or more transmission facilities to approach or exceed their SOL or IROL.

2.1.2. **Notification procedures**. The Reliability Coordinator shall notify all Reliability Coordinators via the Reliability Coordinator Information System (RCIS) as soon as the condition is foreseen. All affected Reliability Coordinators shall check to ensure that Interchange Transactions are posted in the IDC.

2.2. TLR Level 2 — Hold transfers at present level to prevent SOL or IROL Violations

2.2.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 2:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.

2.2.2. **Holding procedures**. The Reliability Coordinator shall be allowed to hold the implementation of any additional Interchange Transactions or Market Flows that are at or above the Curtailment Threshold. However, the Reliability Coordinator should allow additional Interchange Transactions that flow across the Constrained Facility if their flow reduces the loading on the Constrained Facility or has a Transfer Distribution Factor less than the Curtailment Threshold. All Interchange Transactions using Firm Point-to-Point Transmission Service shall be allowed to start and all firm Market Flows shall be allowed to start.

2.2.3. TLR Level 2 is a transient state, which requires a quick decision to proceed to higher TLR Levels (3 and above) to allow Interchange Transactions and Market Flows to be implemented according to their transmission reservation priority.

The time for being in TLR Level 2 should be no more than 30 minutes, with the understanding that there may be circumstances where this time may be exceeded. If the time in TLR Level 2 exceeds 30 minutes, the Reliability Coordinator shall document this action on the TLR Log.

2.3. TLR Level 3a — Reallocation of Transmission Service by curtailing Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Market Flows and 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 or Non-firm Market Flows are flowing on those facilities.
- The Transmission Provider has previously approved a higher priority Point-to-Point Transmission Service reservation over which a Transmission Customer wishes to begin an Interchange Transaction.

2.3.2. Reallocation procedures to allow Interchange Transactions using higher priority Point-to-Point Transmission Service to start or to allow higher priority Market Flows to flow. The Reliability Coordinator with the constraint shall give preference to those Interchange Transactions using Firm Point-to-Point Transmission Service and Firm Market Flows, followed by those using higher priority Non-firm Point-to-Point Transmission Service as specified in Section 3. "Interchange Transaction and Market Flow Curtailment Order." Interchange Transactions or Market Flows that have been held or curtailed as prescribed in this Section shall be reallocated (reloaded) according to their Transmission Service priorities when operating conditions permit as specified in Section 6. "Interchange Transaction and Market Flow Reallocation During TLR Level 3a and 5a."

2.3.2.1. The Reliability Coordinator shall displace Interchange Transactions and Market Flows with lower priority Transmission Service using Interchange Transactions and Market Flows having higher priority Non-firm or Firm Transmission Service.

2.3.2.2. The Reliability Coordinator shall not curtail Non-firm Market Flow or Interchange Transactions using Non-firm Transmission Service to allow the start or increase of another Non-firm Market Flow Interchange Transaction having the same priority Non-firm Transmission Service.

2.3.2.3. If there are insufficient Non-firm Market Flows or Interchange Transactions using Non-firm Point-to-Point Transmission Service that can be curtailed to allow for Firm Market Flows or Interchange Transactions using Firm Point-to-Point Transmission Service to begin, the Reliability Coordinator shall proceed to TLR Level 5a.

2.3.2.4. The Reliability Coordinator shall reload curtailed Market Flows and Interchange Transactions prior to allowing the start of new or increased Market Flows or Interchange Transactions.

2.3.2.4.1. Interchange Transactions whose tags were submitted prior to the TLR Level 2 or Level 3a being called, but were subsequently held from starting, are considered to have been curtailed and thus would be reloaded the same time as the curtailed Interchange Transactions.

2.3.2.5. The Reliability Coordinator shall fill available transmission capability by reloading or starting eligible Market Flows or Transactions on a pro-rata basis.

2.3.2.6. The Reliability Coordinator shall consider transactions whose tags meet the approved tag submission deadline for Reallocation for the upcoming hour. Tags submitted after this deadline shall be considered for Reallocation the following hour.

2.4. TLR Level 3b — Curtail Non-firm Market Flows and 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.
- Non-firm Market Flows or Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.

2.4.2. Holding new Market Flows or Interchange Transactions. The Reliability Coordinator shall hold all new Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold during the period of the SOL or IROL Violation. The Reliability Coordinator shall allow Firm Market Flows and Interchange Transactions using Firm Point-to-Point Transmission Service to start if they are submitted to the IDC within specific time limits as explained in Section 7. "Interchange Transaction and Market Flow Curtailments during TLR Level 3b."

2.4.3. Curtailment procedures to mitigate an SOL or IROL. The Reliability Coordinator shall curtail Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold as specified in Section 3, "Interchange Transaction and Market Flow Curtailment Order.**"**

2.5. TLR Level 4 — Reconfigure Transmission

2.5.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 4**:**

- One or more Transmission Facilities are above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken.

2.5.2. Holding new Market Flows and Interchange Transactions. The Reliability Coordinator shall hold all new Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold during the period of the SOL or IROL Violation. The Reliability Coordinator shall allow Firm Market Flows and Interchange Transactions using Firm Point-to-Point Transmission Service to start if they are submitted to the IDC by 25 minutes past the hour or the time at which the TLR Level 4 is called, whichever is later. See Appendix E, Section E2 – Timing Requirements.

2.5.3. Reconfiguration procedures. Following the curtailment of all Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold in Level 3b that impact the Constrained Facilities, if a SOL or IROL violation is imminent or occurring, the Reliability Coordinator(s) shall request that the affected Transmission Operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint. Specific details are explained in Section 4, "Principles for Mitigating Constraints On and Off the Contract Path".

2.6. TLR Level 5a — Reallocation of Transmission Service by curtailing Firm Market Flows and Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Firm Market Flows and 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 Non-firm Market Flows and 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 or increase a Firm Market Flow that would result in a SOL or IROL violation.
- No further transmission reconfiguration is possible or effective.

2.6.2. Reallocation procedures to allow new Firm Market Flows or Interchange Transactions using Firm Point-to-Point Transmission Service to start. The Reliability Coordinator shall use the following three-step process for Reallocation of Firm Market Flows or Interchange Transactions using Firm Point-to-Point Transmission Service:

2.6.2.1. Step 1 — Identify available redispatch options. The Reliability Coordinator shall assist the Transmission Operator(s) in identifying those known redispatch options that are available to the Transmission Customer that will mitigate the loading on the Constrained Facilities. If such redispatch options are deemed insufficient to mitigate loading on the Constrained Facilities, the Reliability Coordinator shall proceed to implement these options while proceeding to Steps 2 and 3 below.

2.6.2.2. Step 2 — The Reliability Coordinator shall calculate the percent of the overload on the Constrained Facility caused by both Firm Point-to-Point Transmission Service (at or above the Curtailment Threshold) and the Transmission Provider's Network Integration Transmission Service and Native Load, as required by the Transmission Provider's filed tariff. This is described in Section 5, "Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service."

2.6.2.3. Step 3 — Curtail Firm Market Flows and Interchange Transactions using Firm Transmission Service. The Reliability Coordinator shall curtail or reallocate on a pro-rata basis (based on the MW level of the MW total to all such Market Flows and Interchange Transactions), those Market Flows and Interchange Transactions as calculated in Section 7.2.2 over the Constrained Facilities. (See also Section 6, "Interchange Transaction and Market Flow Reallocation during TLR 3a and 5a.") The Reliability Coordinator shall assist the Transmission Provider in curtailing Transmission Service to Network Integration Transmission Service customers and Native Load if such curtailments are required by the Transmission Provider's tariff. Available redispatch options will continue to be implemented.

2.7. TLR Level 5b — Curtail Firm Market Flows and 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 Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- No further transmission reconfiguration is possible or effective.

2.7.2. The Reliability Coordinator shall use the following three-step process for curtailment of Firm Market Flows and Interchange Transactions using Firm Point-to-Point Transmission Service:

2.7.2.1. Step 1 — Identify available redispatch options. The Reliability Coordinator shall assist the Transmission Operator(s) in identifying those known redispatch options that are available to the Transmission Customer that will mitigate the loading on the Constrained Facilities. If such redispatch options are deemed insufficient to mitigate loading on the Constrained Facilities, the Reliability Coordinator shall proceed to implement these options while proceeding to Steps 2 and 3 below.

2.7.2.2. Step 2 — The Reliability Coordinator shall calculate the percent of the overload on the Constrained Facility caused by both Firm Point-to-Point Transmission Service (at or above the Curtailment Threshold) and the Transmission Provider's Network Integration Transmission Service and Native Load, as required by the Transmission Provider's filed tariff. This is described in Section 5, "Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service."

2.7.2.3. Step 3 — Curtailment of Firm Market Flows and Interchange Transactions using Firm Transmission Service. At this point, the Reliability Coordinator shall begin the process of curtailing Market Flows and Interchange Transactions as calculated in Section 2.7.2.2 over the Constrained Facilities using Firm Point-to-Point Transmission Service until the SOL or IROL violation has been mitigated. The Reliability Coordinator shall assist the Transmission Provider in curtailing Transmission Service to Network Integration Transmission Service customers and Native Load if such curtailments are required by the Transmission Providers' tariff. Available redispatch options will continue to be implemented.

2.8. TLR Level 6 — Emergency Procedures

2.8.1. The Reliability Coordinator shall use following circumstances to establish the need for entering TLR Level 6**:**

- One or more Transmission Facilities are above their SOL or IROL.
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.

2.8.2. Implementing emergency procedures. If the Reliability Coordinator deems that transmission loading is critical to Bulk Electric System reliability, the Reliability Coordinator shall immediately direct the Balancing Authorities and Transmission Operators in its Reliability Area to redispatch generation, or reconfigure transmission, or reduce load to mitigate the critical condition until Market Flows and Interchange Transactions can be reduced utilizing the TLR Procedures or other procedures to return the system to a secure state. All Balancing Authorities and Transmission Operators shall comply with all requests from their Reliability Coordinator.

2.9. TLR Level 0 — TLR concluded

2.9.1. Market Flow and 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 Market Flows and Interchange Transactions to be reestablished at its discretion. Those with the highest transmission priorities shall be reestablished first if possible.

3. Interchange Transaction and Market Flow Curtailment Order for use in TLR Procedures

3.1. Priority of Interchange Transactions

3.1.1. Interchange Transaction curtailment priority shall be determined by the Transmission Service reserved over the constrained facility(ies) as follows:

Transmission Service Priorities

Priority 0. Next-hour Market Service — NX*

Priority 1. Service over secondary receipt and delivery points — NS

Priority 2. Non-Firm Point-to-Point Hourly Service — NH

Priority 3. Non-Firm Point-to-Point Daily Service — ND

Priority 4. Non-Firm Point-to-Point Weekly Service — NW

Priority 5. Non-Firm Point-to-Point Monthly Service — NM

Priority 6. Network Integration Transmission Service from sources not designated as network resources — NN

Priority 7. Firm Point-to-Point Transmission Service — F and Network Integration Transmission Service from Designated Resources — FN

3.1.2. The curtailment priority for Interchange Transactions that do not have a Transmission Service reservation over the constrained facility(ies) shall be defined by the lowest priority of the individual reserved transmission segments.

3.2. Priority of Market Flows

3.2.1. Market Flow curtailment priority shall be determined by the Transmission Service reserved over the constrained facility(ies) as follows:

Transmission Service Priorities

Priority 2. Non-Firm Hourly Market Flow — NH

Priority 6. ~~Market Flow~~ Non-Firm Economic Dispatch Market Flow — NN

Priority 7. Firm Generation to Load Market Flow — F

3.3. Curtailment of Non-firm Market Flows and Interchange Transactions Using Non-firm Transmission Service

3.3.1. The Reliability Coordinator shall direct the curtailment of Non-firm Market Flows and Interchange Transactions using Non-firm Transmission Service that are at or above the Curtailment Threshold for the following TLR Levels:

3.3.1.1. TLR Level 3a. Enable Market Flows and Interchange Transactions using a higher Transmission reservation priority to be implemented, or

3.3.1.2. TLR Level 3b. Mitigate an SOL or IROL violation.

3.4. Curtailment of Firm Market Flows and Interchange Transactions Using Firm Transmission Service

3.4.1. The Reliability Coordinator shall direct the curtailment of Firm Market Flows and Interchange Transactions using Firm Transmission Service that are at or above the Curtailment Threshold for the following TLR Levels:

3.4.1.1. TLR Level 5a. Enable additional Firm Market Flows and Interchange Transactions using Firm Point-to-Point Transmission Service to be implemented after all Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Service have been curtailed, or

3.4.1.2. TLR Level 5b. Mitigate a SOL or IROL violation that remains after all Non-firm Market Flows and Interchange Transactions using Non-firm Transmission Service has been curtailed under TLR Level 3b, and following attempts to reconfigure transmission under TLR Level 4.

4. Mitigating Constraints On and Off the Contract Path during TLR

Introduction

Reserving Transmission Service for an Interchange Transaction along a Contract Path may not reflect the actual distribution of the power flows over the transmission network from generation source to load sink. Interchange Transactions arranged over a Contract Path may, therefore, overload transmission elements on other electrically parallel paths.

The curtailment priority of an Interchange Transaction depends on whether the Constrained Facility is on or off the Contract Path as detailed below.

4.1. Constraints ON the Contract Path

4.1.1. The Reliability Coordinator initiating TLR shall consider the entire Interchange Transaction non-firm if the transmission link (i.e., a segment on the Contract Path) on the Constrained Facility is Non-firm Point-to-Point Transmission Service, even if other links in the Contract Path are firm. When the Constrained Facility is on the Contract Path, the Interchange Transaction takes on the Transmission Service Priority of the Transmission Service link with the Constrained Facility regardless of the Transmission Service Priority on the other links along the Contract Path.

Discussion. The Transmission Operator simply has to call its Reliability Coordinator, request the TLR Procedure be initiated, and allow the curtailments of all Interchange Transactions that are at or above the Curtailment Threshold to progress until the relief is realized. Firm Point-to-Point Transmission Service links elsewhere in the Contract Path do not obligate Transmission Providers providing Non-firm Point-to-Point Transmission Service to treat the transaction as firm. For curtailment purposes, the Interchange Transaction's priority will be the priority of the Transmission Service link with the Constrained Facility. (See Requirement 4.1.2 below.)

4.1.2. The Reliability Coordinator initiating TLR shall consider the entire Interchange Transaction firm if the transmission link on the Constrained Facility is Firm Point-to-Point Transmission Service, even if other links in the Contract Path are non-firm.

Discussion. The curtailment priority of an Interchange Transaction on a Contract Path link is not affected by the Transmission Service Priorities arranged with other links on the Contract Path. If the Constrained Facility is on a Firm Point-to-Point Transmission Service Contract Path link, then the curtailment priority of the Interchange Transaction is considered firm regardless of the Transmission Service arrangements elsewhere on the Contract Path. If the Transmission Provider provides its services under the FERC pro forma tariff, it may also be obligated to offer its Transmission Customer alternate receipt and delivery points, thus allowing the customer to curtail its Transmission Service over the Constrained Facilities.

4.2. Constraints OFF the Contract Path

4.2.1. The Reliability Coordinator initiating TLR shall consider the entire Interchange Transaction non-firm if none of the transmission links on the Contract Path are on the Constrained Facility and if any of the transmission links on the Contract Path are Non-firm Point-to-Point Transmission Service; the Interchange

Transaction shall take on the lowest Transmission Service Priority of all Transmission Service links along the Contract Path.

Discussion. An Interchange Transaction arranged over a Contract Path where one or more individual links consist of Non-firm Point-to-Point Transmission Service is considered to be a non-firm Interchange Transaction for Constrained Facilities off the Contract Path. Sufficient Interchange Transactions that are at or above the Curtailment Threshold will be curtailed before any Interchange Transactions using Firm Point-to-Point Transmission Service are curtailed. The priority level for curtailment purposes will be the lowest level of Transmission Service arranged for on the Contract Path.

4.2.2. The Reliability Coordinator initiating TLR shall consider the entire Interchange Transaction firm if all of the transmission links on the Contract Path are Firm Point-to-Point Transmission Service, even if none of the transmission links are on the Constrained Facility and shall not be curtailed to relieve a Constraint off the Contract Path until all non-firm Interchange Transactions that are at or above the Curtailment Threshold have been curtailed.

Discussion. If the entire Contract Path is Firm Point-to-Point Transmission Service, then the TLR procedure will treat the Interchange Transaction as firm, even for Constraints off the Contract Path, and will not curtail that Interchange Transaction until all non-firm Interchange Transactions that are at or above the Curtailment Threshold have been curtailed. However, Transmission Providers off the Contract Path are not obligated to reconfigure their transmission system or provide other congestion management procedures unless special arrangements are in place. Because the Interchange Transaction is considered firm everywhere, the Reliability Coordinator may attempt to arrange for Transmission Operators to reconfigure transmission or provide other congestion management options or Balancing Authorities to redispatch, even if they are off the Contract Path, to try to avoid curtailing the Interchange Transaction that is using the Firm Point-to-Point Transmission Service.

5. Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Market Flows or Firm Transmission Service during TLR

Introduction

The provision of Point-to-Point Transmission Service, Network Integration Transmission Service and service to Native Load results in parallel flows on the transmission network of other Transmission Operators. When a transmission facility becomes constrained curtailment of Market Flows and Interchange Transactions is required to allow Market Flows and Interchange Transactions of higher priority to be scheduled (Reallocation) or to provide transmission loading relief (Curtailment). An Interchange Transaction is considered for Reallocation or Curtailment if its Transfer Distribution Factor (TDF) exceeds the TLR Curtailment Threshold.

In compliance with the Transmission Service Provider tariffs, Interchange Transactions using Non-firm Point-to-Point Transmission Service and Non-firm Market Flows are curtailed first (TLR Level 3a and 3b), followed by transmission reconfiguration (TLR Level 4), and then the curtailment of Firm Market Flows and Interchange Transactions using Firm Point-to-Point Transmission Service, Network Integration Transmission Service and service to Native Load (TLR Level 5a and 5b). Curtailment of Firm Point-to-Point Transmission Service shall be accompanied by the comparable curtailment of Network Integration Transmission Service and service to Native Load to the degree that these three Transmission Services contribute to the Constraint.

5.1. Requirements

A methodology, called the Per Generator Method without Counter Flow, or simply the Per Generator Method, has been programmed into the IDC to calculate the portion of parallel flows on any Constrained Facility due to service to Native Load of each Balancing Authority. The following requirements are necessary to assure comparable Reallocation or Curtailment of firm Transmission Service:

5.1.1. The Reliability Coordinator initiating a curtailment shall identify for curtailment all firm Transmission Services (i.e. Point-to-Point, Network Integration and service to Native Load) that contribute to the flow on any Constrained Facility by an amount greater than or equal to the Curtailment Threshold on a pro rata basis.

5.1.2. For Firm Point-to-Point Transmission Services, the Transfer Distribution Factors must be greater than or equal to the Curtailment Threshold.

5.1.3. For Network Integration Transmission Service and service to Native Load, the Generator-To-Load Distribution Factors must be greater than or equal to the Curtailment Threshold.

5.1.4. The Per Generator Method shall assign the amount of Constrained Facility relief that must be achieved by each Balancing Authority's Network Integration Transmission Service or service to Native Load. It shall not specify how the reduction will be achieved.

5.1.5. All Balancing Authorities in the Eastern Interconnection shall be obligated to achieve the amount of Constrained Facility relief assigned to them by the Per Generator Method.

5.1.6. The implementation of the Per Generator Method shall be based on transmission and generation information that is readily available.

5.2. Calculation Method

The calculation of the flow on a Constrained Facility due to Network Integration Transmission Service or service to Native Load shall be based on the Generation Shift Factors (GSFs) of a Balancing Authority's assigned generation and the Load Shift Factors (LSFs) of its native load, relative to the system swing bus. The GSFs shall be calculated from a single bus location in the IDC. The IDC shall report all generators assigned to native load for which the GLDF is greater than or equal to the Curtailment Threshold.

5.3. Market Flow Calculation Method

Similar to the Per Generator Method, the Market Flow calculation method is based on Generator Shift Factors (GSFs) of a market area's assigned generation and the Load Shift Factors (LSFs) of its load on a specific Flowgate, relative to a system swing bus. The GSFs are calculated from a single bus location in the base case (e.g. the terminal bus of each generator) while the LSFs are either defined as a general scaling of the market area's load in total or general scaling of the market area's load by each defined balancing zone within the market area. The Generator to Load Distribution Factor (GLDF) is determined through superposition by subtracting the LSF from the GSF.

The determination of the Market Flow contribution of a unit to a specific Flowgate is the product of the generator's GLDF multiplied by the actual output (in megawatts) of that generator being used to either serve load in the Balancing Authority participating in the market wherein the generator resides or load in the balancing zone participating in the market wherein the generator resides. If the market contains multiple Balancing Authorities, the output of the generator being used to serve loads in other Balancing Authority's areas or balancing zone areas that are participating in the market must be multiplied by an appropriate GLDF representing that transactional distribution of flow. The total Market Flow on a specific Flowgate is calculated in each direction; forward Market Flows is the sum of the positive Market Flow contributions of each generator within the market area, while reverse Market Flow is the sum of the negative Market Flow contributions of each generator within the market area. Impacts of tagged transactions representing delivery of energy not dispatched by the market and energy dispatched by the market but delivered outside the footprint will not be included in market flow.

5.3.1. The Market Flow calculation method shall consider all market area generators.

5.3.2. The Market Flow calculation method shall include all positively impacting flows down to three percent.

5.3.3. The Market Flow calculation method shall use the real-time output level of each individual market area generator.

5.1.4. The Market Flow calculation method shall use market area load based on the real-time demand at each individual bus.

6. Interchange Transaction and Market Flow Reallocation During TLR Levels 3a and 5a

Introduction

This section provides the details for implementing TLR Levels 3a and 5a, both of which provide a means for Reallocation of Transmission Service.

TLR Level 3a accomplishes Reallocation by curtailing Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow higher priority Market Flows and Interchange Transactions using higher priority Non-firm or Firm Point-to-Point Transmission Service to start. (See **Requirement 2.3, "TLR Level 3a.")** When a TLR Level 3a is in effect, Reliability Coordinators shall reallocate Market Flows and Interchange Transactions according to the Market Flows' and Transactions' Transmission Service Priorities. Reallocation also includes the orderly reloading of Market Flows and Transactions by priority when conditions permit curtailed Market Flows and Transactions to be reinstated.

TLR Level 5a accomplishes Reallocation by curtailing Firm Market Flows and Interchange Transactions using Firm Point-to-Point Transmission Service on a pro-rata basis to allow new Interchange Transactions using Firm Point-to-Point Transmission Service or additional Firm Market Flow to begin, also on a pro-rata basis. (See **Requirement 2.6, "TLR Level 5a.")**

6.1. Requirements

The basic requirements for Transaction Reallocation are as follows:

6.1.1. When identifying Market Flows or transactions for Reallocation the Reliability Coordinator shall normally only involve Curtailments of Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service during TLR 3a. However, Reallocation may be used during TLR 5a to allow the implementation of additional Firm Market Flows and Interchange Transactions using Firm Transmission Service on a pro-rata basis.

6.1.2. When identifying transactions for Reallocation, the Reliability Coordinator shall only consider those Interchange Transactions at or above the Curtailment Threshold for which a TLR 2 or higher is called.

6.1.3. When identifying Market Flows and transactions for Reallocation, the Reliability Coordinator shall displace Market Flows and Interchange Transactions utilizing lower priority Transmission Service with higher priority Market Flows and Interchange Transactions utilizing higher Transmission Service Priority.

6.1.4. When identifying Market Flows or transactions for Reallocation, the Reliability Coordinator shall not curtail Non-firm Market Flows or Interchange Transactions using Non-firm Transmission Service to allow the start or increase of another transaction having the same Non-Firm Transmission Service Priority (marginal "bucket") or the start or increase of additional Market Flow having the same Priority.

6.1.5. When identifying Market Flow and transactions for Reallocation, the Reliability Coordinator shall reload curtailed Market Flows and Interchange Transactions prior to starting new or increasing existing Market Flows and Interchange Transactions.

6.1.6. Interchange Transactions whose tags were submitted prior to the TLR 2 or 3a being called, but were subsequently held from starting because they failed to meet the approved tag submission deadline for Reallocation (see Section 6.2, "Communications and Timing Requirements"), shall be considered to have been curtailed and thus would be eligible for reload at the same time as the curtailed Interchange Transaction.

6.1.7. The Reliability Coordinator shall reload or start all eligible Market Flows and Transactions on a pro-rata basis.

6.1.8. Interchange Transactions whose tags meet the approved tag submission deadline for Reallocation (see Section 6.2, "Communications and Timing Requirements") shall be considered for Reallocation for the upcoming hour. (However, Interchange Transactions using Firm Point-to-Point Transmission Service shall be allowed to start as scheduled.) Interchange Transactions whose tags are submitted to the IDC after the approved tag submission deadline for Reallocation shall be considered for Reallocation the following hour. This applies to Interchange Transactions using either Non-firm Point-to-Point Transmission Service or Firm Point-to-Point Transmission Service. If an Interchange Transaction using Firm Interchange Transaction is submitted after the approved tag submission deadline and after the TLR is declared, that Transaction shall be held and then allowed to start in the upcoming hour.

It should be noted that calling a TLR 3a does not necessarily mean that Non-firm Market Flows and Interchange Transactions using Non-firm Transmission Service will always be curtailed the next hour. However, TLR Levels 3a and 5a trigger the approved tag submission deadline for Reallocation requirements and allow for a coordinated assessment of all Market Flows and Interchange Transactions tagged to start the upcoming hour.

6.2. Communication and Timing Requirements

The following timeline shall be utilized to support Reallocation decisions during TLR Levels 3a or 5a. See Figures 2 and 3 for a depiction of the Reallocation Time Line.

6.2.1. Time Convention. In this document, the beginning of the current hour shall be referenced as 00:00. The beginning of the next hour shall be referenced as 01:00. The end of the next hour shall be referenced as 02:00. See Figure 1.

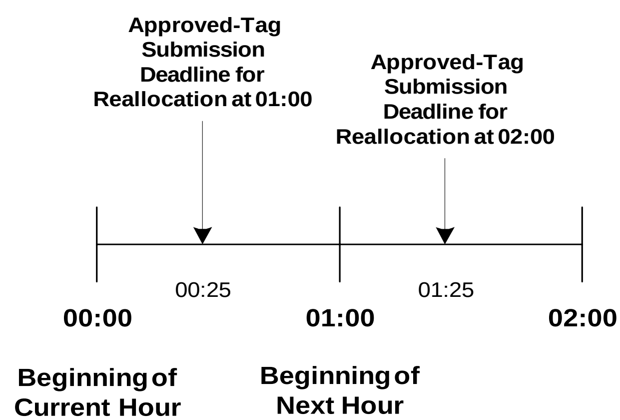


Figure 1 - Timeline showing Approved-tag Submission Deadline for Reallocation

6.2.2. Approved tag submission deadline for Reallocation Reliability Coordinators shall consider all approved Tags for Interchange Transactions at or above the Curtailment Threshold that have been submitted to the IDC by 00:25 for Reallocation at 01:00. See Figure 1. However, Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled.

6.2.2.1. Reliability Coordinators shall consider all approved tags submitted to the IDC beyond these deadlines for Reallocation at 02:00 (for both Firm and Non-firm Point-to-Point Transmission Service). However, these Interchange Transactions will not be allowed to start or increase at 01:00.

6.2.2.2. The approved tag submission deadline for Reallocation shall cease to be in effect as soon as the TLR level is reduced to 1 or 0.

6.2.3. **Off-hour Transactions**. Interchange Transactions with a start time other than *xx*:00 shall be considered for Reallocation at *xx*+1:00. For example, an Interchange Transaction with a start time of 01:05 and whose Tag was submitted at 00:15 will be considered for Reallocation at 02:00.

6.2.4. **Tag Evaluation Period.** Balancing Authorities and Transmission Providers shall evaluate all tags submitted for Reallocation and shall communicate approval or rejection by 00:25.

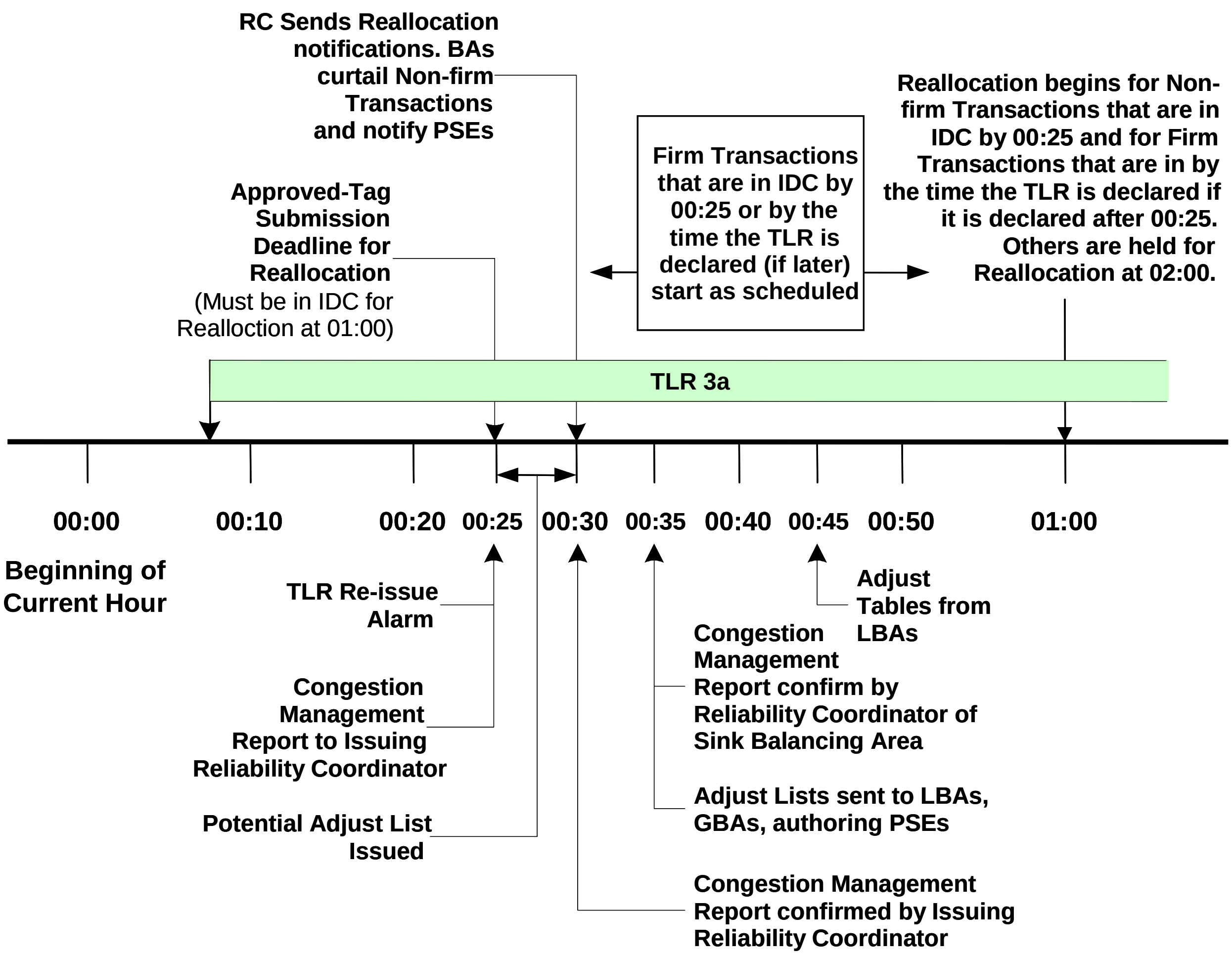


Figure 2 — Reallocation Timing for TLR 3a Called at 00:08

6.2.5. **Collective Scheduling Assessment Period.** At 00:25, the initiating Reliability Coordinator (the one who called and still has a TLR 3a or 5a in effect) shall run the IDC to obtain a three-part list of Market Flows and Interchange Transactions including their transaction status:

6.2.5.1. Interchange Transactions that may start, increase, or reload shall have a status of PROCEED, and

6.2.5.2. Interchange Transactions that must be curtailed or Interchange Transactions whose tags were submitted prior to the TLR 2 or higher being declared but were not permitted to start or increase shall have a status of CURTAILED, and

6.2.5.3. Interchange Transactions that are entered into the IDC after 00:25 shall have a status of HOLD and be considered for Reallocation at 02:00. Also, Interchange Transactions using Non-firm Point-to-Point Transmission Service submitted after TLR 2 or higher was declared ("post-tagged") but have not been allowed to start shall retain the HOLD status until given permission to PROCEED or E-Tag expires. (Note: TLR Level 2 does not hold Interchange Transactions using Firm Point-to-Point Transmission Service).

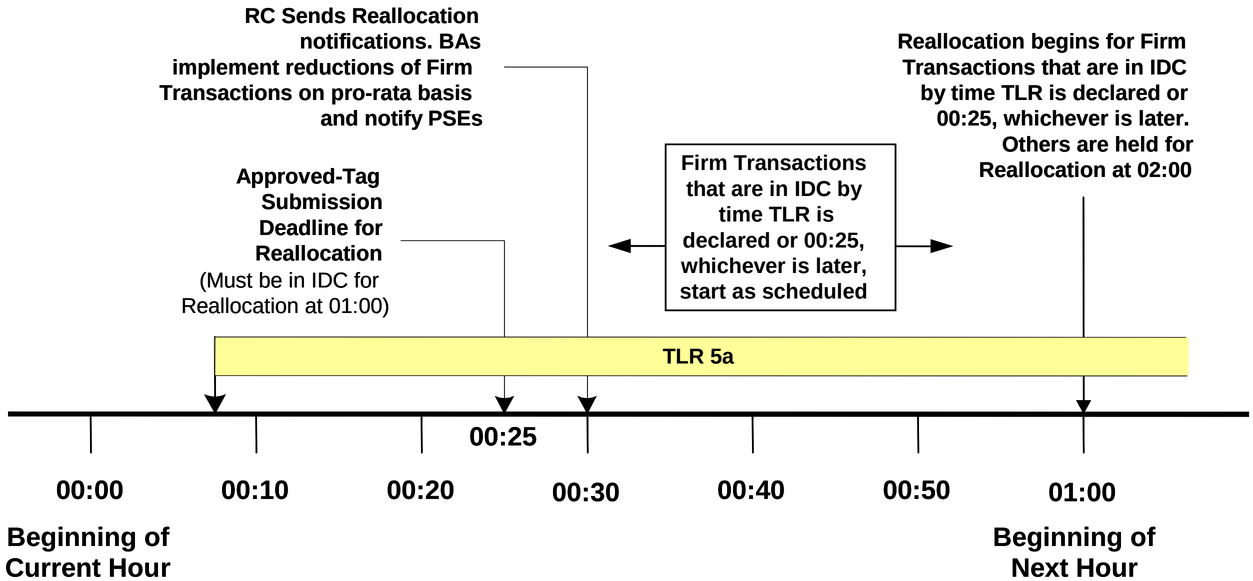


Figure 3 — Reallocation timing for TLR 5a called at 00:08.

6.2.5.4. The initiating Reliability Coordinator shall communicate the list of Interchange Transactions to the appropriate sink Reliability Coordinators via the IDC, who shall in turn communicate the list to the Sink Balancing Authorities at 00:30 for appropriate actions to implement Interchange Transactions (CURTAIL, PROCEED or HOLD). The IDC will prompt the initiating Reliability Coordinator to input the necessary information (i.e., maximum flowgate loading and curtailment requirement) into the IDC by 00:25.

6.2.5.5. Subsequent required reports before 01:00 shall allow the Reliability Coordinators to include those Interchange Transactions whose tags were submitted to the IDC after the Approved-Tag Submission Time for Reallocation and were given the HOLD status (not permitted to PROCEED). Transactions at or above the Curtailment Threshold that are not indicated as "PROCEED" on Reload/Reallocation Report shall not be permitted to start or increase the next hour.

Discussion: Note that TLR 2 does not initiate the approved tag submission deadline for Reallocation, but a TLR3a or 5a does. It is, however, important to recognize the time when a TLR 2 is called, where applicable, to determine the status of a held transaction — "CURTAILED" if tagged before the TLR was called but "HOLD" if tagged after the TLR was called.

6.2.5.6. In running the IDC, the Reliability Coordinator shall have an option to specify the maximum loading of the Constrained Facility by all Interchange Transactions using Point-to-Point Transmission Service.

Discussion: This allows the Reliability Coordinator to take into consideration SOLs or IROLs and changes in Transactions using other than Point-to-Point service taken under the Open Access Transmission Tariff. This option is needed to avoid loading the Constrained Facility to its limit with known Interchange Transactions while other factors push the facility into a SOL or IROL violation and hence triggering the declaration of a TLR 3b or 5b.

6.2.5.7. Notification of Interchange Transaction status shall be provided from the IDC to the Reliability Coordinators via an IDC Report. The Reliability Coordinators shall communicate this information to the Balancing Authorities and Transmission Operators.

Additional reporting and communications details on information posted from the IDC to the NERC TLR website are contained in Appendix E.

6.2.6. **Customer Preferences on Timing to Call TLR 3a or 5a.** Reliability Coordinators shall leave a TLR 2 and call a TLR 3a as soon as possible (but no later than 30 minutes) to initiate the Approved-Tag Submission Deadline and start reallocating Transactions. Nevertheless, recognizing the approved tag submission deadline for Reallocation, from a Transmission Customer perspective, it is preferable that the Reliability Coordinator call a TLR 3a within a certain time period to allow for tag preparation and submission. See Figure 4.

Discussion: A Reliability Coordinator calls a TLR 2 or 3a whenever it deems necessary to indicate that a transmission facility is approaching its SOL or IROL. It is envisioned, though not required, that a TLR 2 or 3a is preceded by a period of a TLR 1 declaration, hence Transmission Customers should normally have advance notice of a potential constraint. For example, a TLR 3a initiated during the period 01:00 to 01:25 would allow the Purchasing-Selling Entity to submit a Tag for entry into the IDC by the Approved-Tag Submission Deadline for Reallocation at 02:00. See Figure 4. However, the preferred time period to declare a TLR 3a or 5a would be between 00:40 (when tags for Next Hour Market have been submitted) and 01:15. This will allow the Transmission

Customers a range of 15 to 35 minutes to prepare and submit tags. (Note: In this situation, the Reliability Coordinator would need to reissue the TLR 3a at 01:00.)

It must be emphasized that the preferred time period is not a requirement, and should not in any way impede a Reliability Coordinator's ability to declare a TLR 3a, 3b, 4, 5a, or 5b whenever the need arises.

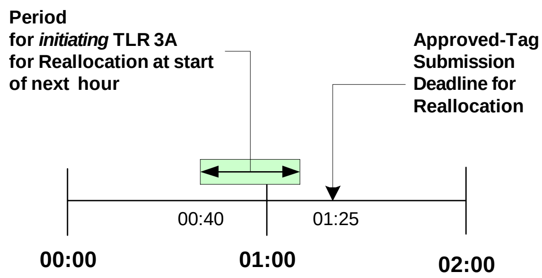


Figure 4. "Ideal" time for issuing TLR 3a for Reallocation at 02:00.

7. Interchange Transaction and Market Flow Curtailments During TLR Level 3b

Introduction

This section provides the details for implementing TLR Level 3b, which curtails Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service to assist the Reliability Coordinator to recover from SOL or IROL violations.

TLR Level 3b curtails Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold. (See **Requirement 2.4, "TLR Level 3b.")**. Furthermore, *all* new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold and additional Non-firm Market Flows during the TLR 3b implementation period are halted or held. Firm Market Flows and Transactions using Firm Point-to-Point Transmission Service will be allowed to start if they are submitted to the IDC within specific time limits as explained in Appendix F, "Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service." Those Interchange Transactions using Firm Point-to-Point Transmission Service that are not submitted to the IDC within these time limits will be held.

Requirements

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

7.2. The Reliability Coordinator shall consider only Non-firm Market Flows and those Interchange Transactions at or above the Curtailment Threshold for curtailment, holding, or halting.

7.3. The Reliability Coordinator shall curtail existing Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to provide the required relief on the Constrained Facility.

7.4. The Reliability Coordinator shall curtail additional Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service to provide transmission capacity for Firm Market Flows and Interchange Transactions using Firm Point-to-Point Transmission Service if those Interchange Transactions using Firm Point-to-Point Transmission Service are scheduled to start during the current hour or the following hour.

7.5. The Reliability Coordinator shall not allow existing Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service that are not curtailed to increase (they may flow at the same or reduced level).

7.6. The Reliability Coordinator shall not reallocate Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service during a TLR 3b.

7.7. The Reliability Coordinator shall allow Firm Market Flows and Interchange Transactions using Firm Point-to-Point Transmission Service to start as explained in Appendix F, "Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service."

7.8. The Reliability Coordinator shall progress to TLR Level 5b as necessary if there is still insufficient transmission capacity for Firm Market Flows and Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled after all Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service have been curtailed.

7.9. The IDC shall issue ADJUST Lists to the Generation and Load Balancing Authority Areas and the Purchasing-Selling Entity who submitted the tag. Market Flow relief requirements will also be issued to the responsible Reliability Coordinator. The ADJUST List will include:

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

7.9.2. Interchange Transactions using Firm Point-to-Point Transmission Service that were entered after 00:25 or issuance of TLR 3b (see Case 3 in Appendix F).

7.10. The Sink Balancing Authority shall send the ADJUST Lists back to the IDC and the market entity will submit updated Market Flow information reflecting the Market Flow relief directed by the IDC as soon as possible to ensure the most accurate calculations for actions subsequent to the TLR 3b being called.

7.11. The Reliability Coordinator shall be allowed to call a TLR Level 3a as soon as the SOL or IROL violation that caused the TLR 3b to be called has been mitigated.

7.11.1. If the TLR Level 3a is called before the hour 01, then a Reallocation shall be computed for the start of that hour.

7.11.2. Transactions must be in the IDC by the Approved-tag Submission Deadline for Reallocation (see Requirement 6.2).

8. Non-firm Interchange Transaction and Non-firm Market Flow Curtailments

8.1. The methodology used to apply a weighted impact to each non-firm tagged transaction (Priorities 1 thru 6) for the purposes of curtailment by the IDC is detailed in **Appendix B (Transaction Curtailment Formula).**

8.2. For the purpose of curtailment, the Non-firm Market Flow impacts (Priorities 2 and 6) submitted to the IDC shall be curtailed pro-rata as is done for Interchange Transactions using firm transmission service. This is because several of the values needed to assign a weighted impact using the process listed in Appendix B rely on the availability of a Distribution Factor, which is not defined for Market Flows.

Appendices for Transmission Loading Relief Standard

Appendix A. Market Flow and Transaction Management and Curtailment Process.

Appendix B. Transaction Curtailment Formula.

Appendix C. Sample NERC Transmission Loading Relief Procedure Log.

Appendix D. Examples for Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Market Flow and Firm Transmission Service.

Appendix E. How the IDC Handles Reallocation.

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

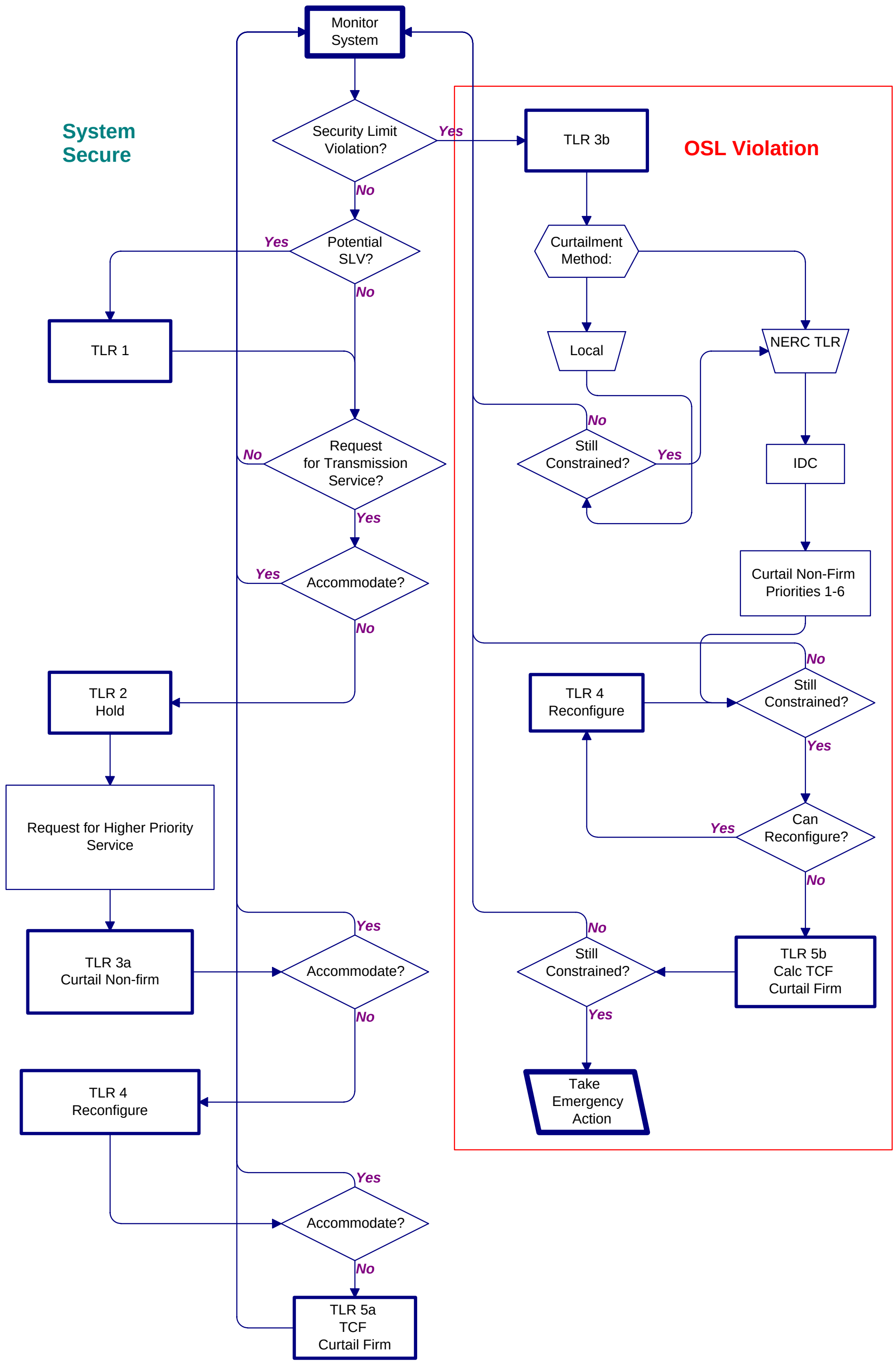
Section E2: Timing Requirements.

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

Appendix G. Examples of On-Path and Off-Path Mitigation.

Appendix A. Market Flow and Transaction Management and Curtailment Process

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



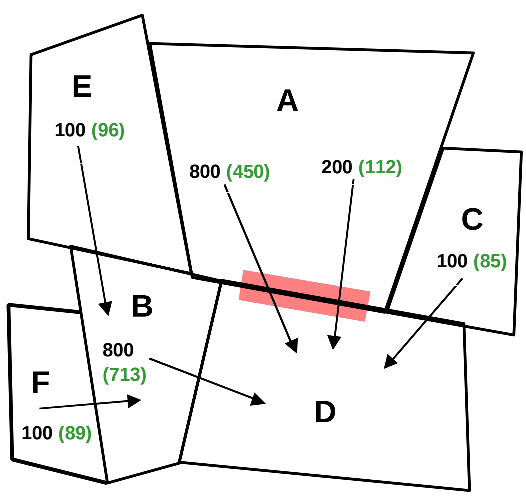
Appendix B. Transaction Curtailment Formula

Example

This example is based on the premise that a transaction should be curtailed in proportion to its Transfer Distribution Factor on the Constraints. Its effect on the interface is a combination of its size in MW and its effect based on its distribution factor.

Column	Description
1. Initial Transaction	Interchange Transaction before the TLR Procedure is implemented.
2. Distribution Factor	Proportional effect of the Transaction over the constrained interface due to the physical arrangement and impedance of the transmission system.
3. Impact on the Interface	Result of multiplying the Transaction MW by the distribution factor. This yields the MW that flow through the constrained interface from the Transaction. Performing this calculation for each Transaction yields the total flow through the constrained interface from all the Interchange Transactions. In this case, 760 MW.
4. Impact Weighting Factor	"Normalization" of the total of the Distribution Factors in Column 2. Calculated by dividing the Distribution Factor for each Transaction by the total of the Distribution Factors.
5. Weighted Maximum Interface Reduction	Multiplying the Impact on the Interface from each Transaction by its Impact Weighting Factor yields a new proportion that is a combination of the MW Impact on the Interface and the Distribution Factor.
6. Interface Reduction	Multiplying the amount needed to reduce the flow over the constrained interface (280 MW) by the normalization of the Weighted Maximum Interface Reduction yields the actual MW reduction that each Transaction must *contribute* to achieve the total reduction.
7. Transaction Reduction	Now divide by the Distribution Factor to see how much the Transaction must be reduced to yield the result calculated in Column 7. Note that the reductions for the first two Interchange Transactions (A-D (1) and A-D (2) are in proportion to their size since their distribution factors are equal.
8. New Transaction Amount	Subtracting the Transaction Reduction from the Initial Transaction yields the New Transaction Amount.
9. Adjusted Impact on Interface	A check to ensure the new constrained interface MW flow has been reduced to the target amount.

	Allocation based on Weighted Impact								
	1	2	3	4	5	6	7	8	9
Transaction ID	Initial Transaction	Distribution Factor	(1)*(2) Impact On Interface	(2)/(2TOT) Impact weighting factor	(3)*(4) Weighted Max Interface Reduction	(5)*(Relief Requested) /(5 Tot) Interface Reduction	(6)/(2) Transaction Reduction	(1)-(7) New Transaction Amount	(8)*(2) Adjusted Impact On Interface
Example 1									
A-D(1)	800	0.6	480	0.34	164.57	209.73	349.54	450.46	270.27
A-D(2)	200	0.6	120	0.34	41.14	52.43	87.39	112.61	67.57
B-D	800	0.15	120	0.09	10.29	13.11	87.39	712.61	106.89
C-D	100	0.2	20	0.11	2.29	2.91	14.56	85.44	17.09
E-B	100	0.05	5	0.03	0.14	0.18	3.64	96.36	4.82
F-B	~~100~~	~~0.15~~	~~15~~	~~0.09~~	~~1.29~~	~~1.64~~	~~10.92~~	~~89.08~~	~~13.36~~
	2100	**1.75**	**760**		**219.71**	**280.00**	**553.45**	**1546.55**	**480.00**
Example 2									
A-D(1)	1000	0.6	600	0.52	313.04	262.16	436.93	563.07	337.84
B-D	800	0.15	120	0.13	15.65	13.11	87.39	712.61	106.89
C-D	100	0.2	20	0.17	3.48	2.91	14.56	85.44	17.09
E-B	100	0.05	5	0.04	0.22	0.18	3.64	96.36	4.82
F-B	~~100~~	~~0.15~~	~~15~~	~~0.13~~	~~1.96~~	~~1.64~~	~~10.92~~	~~89.08~~	~~13.36~~
	2100	**1.15**	**760**		**334.35**	**280.00**	**553.45**	**1546.55**	**480.00**
Example 3									
A-D(1A)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(1B)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(1C)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(1D)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(2)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
B-D	800	0.15	120	0.04	5.07	13.11	87.39	712.61	106.89
C-D	100	0.2	20	0.06	1.13	2.91	14.56	85.44	17.09
E-B	100	0.05	5	0.01	0.07	0.18	3.64	96.36	4.82
F-B	~~100~~	~~0.15~~	~~15~~	~~0.04~~	~~0.63~~	~~1.64~~	~~10.92~~	~~89.08~~	~~13.36~~
	2100	**3.55**	**760**		**108.31**	**280.00**	**553.45**	**1546.55**	**480.00**



Appendix C. Sample NERC Transmission Loading Relief Procedure Log

SAVE FILE DIRECTORY:

NERC TRANSMISSION LOADING RELIEF (TLR) PROCEDURE LOG

FILE SAVED AS: .XLS

INCIDENT:	DATE:	IMPACTED RELIABILITY COORDINATOR:	ID NO:

INITIAL CONDITIONS

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

TLR Levels

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

Priorities

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

TLR ACTIONS

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

Appendix D. Examples for Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Market Flows and Firm Transmission Service

The NERC "**Parallel Flow Calculation Procedure Reference Document**" provides additional information about the criteria used to include generators in the IDC calculation process.

Example of Results of Calculation Method

An example of the output of the IDC calculation of curtailment of Firm Market Flows and firm Transmission Service is provided below for the specific Constrained Facility identified in the *Book of Flowgates* as Flowgate 1368. In this example, a total Firm Point-to-Point contribution to the Constrained Facility, as calculated by the IDC, is assumed to be 21.8 MW.

The table below presents a summary of each Balancing Authority's responsibility to provide relief to the Constrained Facility due to its Network Integration Transmission Service and service to Native Load contribution to the Constrained Facility. In this example, Balancing Authority LAGN would be requested to curtail 17.3 MW of its total of 401.1 MW of flow contribution on the Constrained Facility. See the "**Parallel Flow Calculation Procedure Reference Document**" for additional details regarding the information illustrated in the table (e. g. Scaled P Max and Flowgate NNative Load MW).

In summary, Interchange transactions would be curtailed by a total of 21.8 MW and Network Integration Transmission Service and service to Native Load would be curtailed by a total of 178.2 MW by the five Balancing Authorities identified in the table. These curtailments would provide a total of 200.0 MW of relief to the Constrained Facility.

Sink Reliability Coordinator	Service Point	Scaled P Max	Flowgate NNative Load MW	Current NNative Load Relief	NNative Load Responsibility		NNative Load Responsibility Acknowledgement	
					Inc/Dec	Current Hr	Acknowledge Time	Total MW Resp.
EES	EES	8429.7	2991.4	0.0	128.9	128.9	13:44	128.9
EES	LAGN	1514.0	718.6	0.0	31.0	31.0	13:44	31.0
SOCO	SOCO	5089.2	401.1	0.0	17.3	17.3	13:44	17.3
SWPP	CLEC	235.7	18.0	0.0	0.8	0.8	13:42	0.8
SWPP	LEPA	22.8	4.1	0.0	0.2	0.2	13:42	0.2
Total				**0.0**				

Appendix E. How the IDC Handles Reallocation

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

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

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

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

Information posted from IDC to NERC TLR website.

1. Restricted directions (all source/sink combinations that impact a Constrained Facility(ies) with TLR 2 or higher) will be posted to the NERC TLR website and updated as necessary.

2. TLR Constrained Facility status and Transfer Distribution Factors will continue to be posted to NERC TLR website.

3. Lowest priority of Market Flows and 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 and Market Flows 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 and Market Flow Status

Reloading/Reallocation status will be determined by the IDC for all Market Flows and Interchange Transactions. The Reloading/Reallocation status of each Market Flow and 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 and Market Flow 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 and Market Flows are curtailed and loaded pro-rata within priority level per TLR algorithm.

2. Reloading/Reallocation of Market Flows and 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, Market Flows and Interchange Transactions using lower priority Transmission Service will be curtailed pro-rata to allow higher priority Market Flows and transactions to reload, increase, or start. Equal priority Market Flows and Interchange Transactions will not reload, start, or increase by pro-rata Curtailment of other equal priority Market Flows and 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. During TLR 3a, Firm Market Flows will be allowed to flow as scheduled.

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 Market Flows, 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.

- Changes in next hour Market Flows

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 Market Flow and 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 Market Flows and 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 Market Flows and Point-to-Point Interchange Transactions while respecting the priorities of Market Flows and Interchange Transactions flowing and scheduled to flow the next hour. The intent is to reduce the need for using TLR 3b, which prevents new Market Flows and Interchange Transactions from starting or increasing the next hour.

5. The Reliability Coordinator must allow Market Flows and 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.

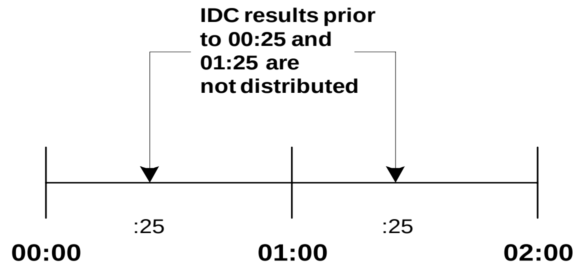


Figure 5 - IDC report may be run prior to 00:25, but results are not distributed.

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 Market Flows and 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 and present the total MW impact of all currently flowing and scheduled Market Flows. 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 and Firm Market Flows. 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 Market Flows and Transactions to be reloaded, reallocated, or curtailed to make room for the Transactions using higher priority Transmission Service and higher priority Market Flows. 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 or Market Flows. The Reliability Coordinator-entered requested relief amount will be used by the IDC to determine the Interchange Transaction Curtailments and flows due to service to Network Customers and Native Load (TLR Level 5b) in order to reduce the SOL or IROL violation on the Constrained Facility by the requested amount.

IDC Calculations and Reporting

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

1. All Interchange Transactions will be arranged by Transmission Service Priority according to the Constrained Path Method. These priorities range from 1 to 6 for the various non-firm Transmission Service products (TLR levels 3a and 3b). Interchange Transactions using Firm Transmission Service (priority 7) are used only in TLR levels 5a and 5b. Next-Hour Market Service is included at priority 0.
2. In a TLR Level 3a the Interchange Transactions using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status. Solely for the purpose of identifying which Interchange Transactions to be loaded under a TLR 3a, various MW levels of an Interchange Transaction may be in different sub-priorities. The sub-priorities are shown in the following table:

Priority	Purpose	Explanation and Conditions
S1	To allow a flowing Interchange Transaction to maintain or reduce its current MW amount in accordance with its energy profile.	The MW amount is the lowest between currently flowing MW amount and the next-hour schedule. The currently flowing MW amount is determined by the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.
S2	To allow a flowing Interchange Transaction that has been curtailed or halted by TLR to reload to the *lesser* of its current-hour MW amount or next-hour schedule in accordance with its energy profile.	The Interchange Transaction MW amount used is determined through the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.
S3	To allow a flowing Transaction to increase from its current-hour schedule to its next-hour schedule in accordance with its energy profile.	The MW amounts used in this sub-priority is determined by the e-tag ENERGY PROFILE table. If the calculated amount is negative, zero is used instead.

Priority	Purpose	Explanation and Conditions
S4	To allow a Transaction that had never started and was submitted to the Tag Authority after the TLR (level 2 or higher) has been declared to begin flowing (i.e., the Interchange Transaction never had an active MW and was submitted to the IDC *after* the first TLR Action of the TLR Event had been declared.)	The Transaction would not be allowed to start until all other Interchange Transactions submitted prior to the TLR with the same priority have been (re)loaded. The MW amount used is the sub-priority is the next-hour schedule determined by the e-tag ENERGY PROFILE table.

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

3. All Interchange Transactions using Firm Transmission Service will be put in the same priority group, and will be Curtailed/Reallocated pro-rata, independent of their current status (curtailed or halted) or time of submittal with respect to TLR issuance (TLR level 5a). Under a TLR 5a, all Interchange Transactions using Non-firm Transmission Service that is at or above the Curtailment Threshold will have been curtailed and hence sub-prioritizing is not required.

All Interchange Transactions processed in a TLR are assigned one of the following statuses:

PROCEED: The Interchange Transaction has started or is allowed to start to the next hour MW schedule amount.

CURTAILED: The Interchange Transaction has started and is curtailed due to the TLR, or it had not started but it was submitted prior to the TLR being declared (level 2 or higher).

HOLD: The Interchange Transaction had never started and it was submitted after the TLR being declared – the Interchange Transaction is held from starting next hour or the transaction had never started and it was submitted to the IDC after the Approved-Tag Submission Deadline – the Interchange Transaction is to be held from starting next hour and is not included in the Reallocation calculations until following hour.

Upon acceptance of the TLR Transaction Reallocation/reloading report by the issuing Reliability Coordinator, the IDC will generate a report to be sent to NERC that will include the PSE name and Tag ID of each Interchange Transaction in the IDC TLR report. The Interchange Transaction will be ranked according to its assigned status of HOLD, CURTAILED or PROCEED. The reloading/Reallocation report will be made available at NERC's public TLR website, and it is NERC's responsibility to format and publish the report.

4. Market Flows for the current hour and the next hour shall be separated into their appropriate priorities and provided to the IDC. The Market Flows shall be represented and made available for curtailment under the appropriate TLR Levels.

   4.1. For the purposes of reallocation, a sub-priority (S1 thru S43) be assigned to these Market Flow impacts by the IDC as follows, using comparable logic as would be used if the Market Flow 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 market operator has recognized the constraint for which TLR has been called. If the calculated amount is negative, zero is used instead.
S2	To allow Market Flow that has been curtailed or halted by TLR to reload to its desired amount for the current-hour.	This is the difference between the current hour unconstrained market flow and the current Market Flow. If the current-hour unconstrained Market Flow is not available, the IDC will use the most recent Market Flow since the TLR was first issued or, if not available, the Market Flow at the time the TLR was first issued.
S3	To allow a Market Flow to increase to its next-hour desired amount.	This is the difference between the next hour and current hour unconstrained Market Flow.
S4	Adjustment from S1 for market not meeting its previous hour's Curtailment requirement, if applicable.	The Curtailment requirement is verified by comparing the next hour Market Flow and the actual Market Flow to ensure the previous hour's Curtailment has been met. This is the difference between the next hour Market Flow and the actual Market Flow provided by the market entity. S4 shall not be less than zero MW.

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 and Market Flows are allowed to flow. In order to provide the Reliability Coordinators with a view of the Market Flows and 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

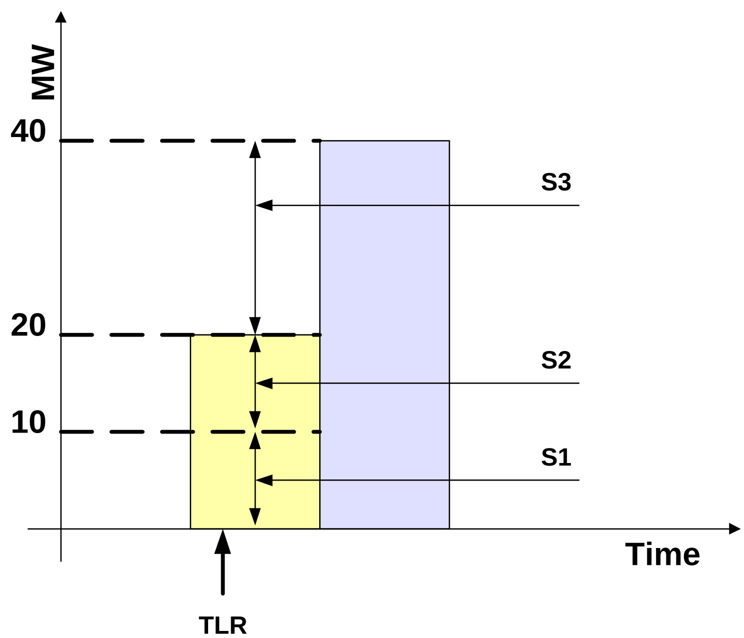
There are cases in which a tag may be marked with a composite state of ATTN_REQD to indicate that tag Authority/Approval failed to communicate or there is an inconsistency between the validation software of different tag Authority/Approval entities. In this situation, the tag is no longer subject to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

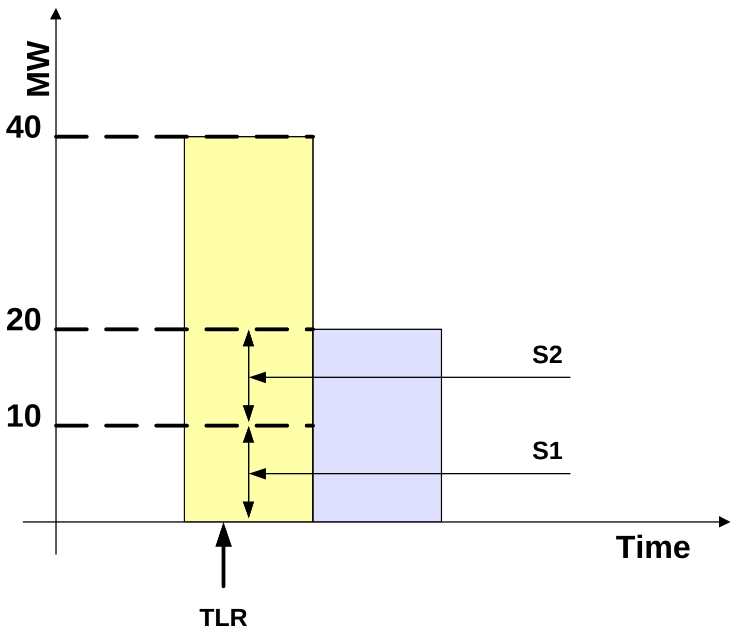


Sub-priorities for Transaction MW:

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

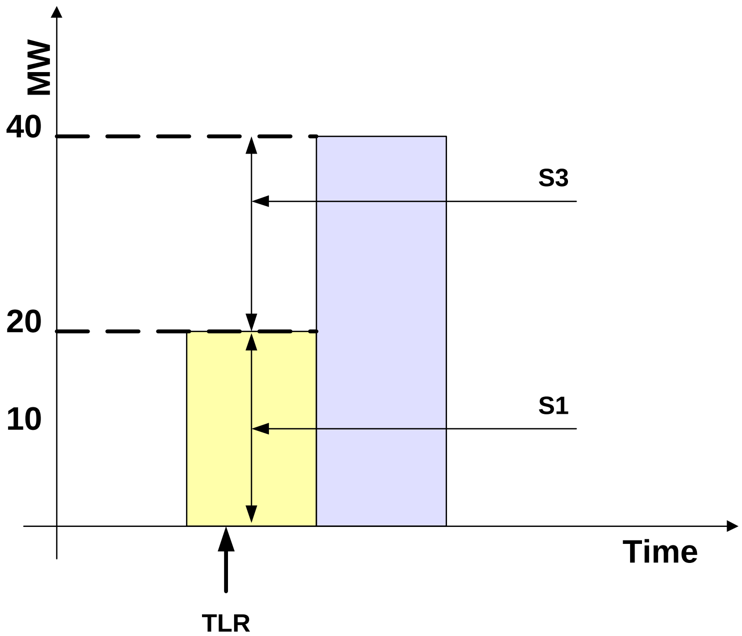


Sub-priorities for Transaction MW:

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

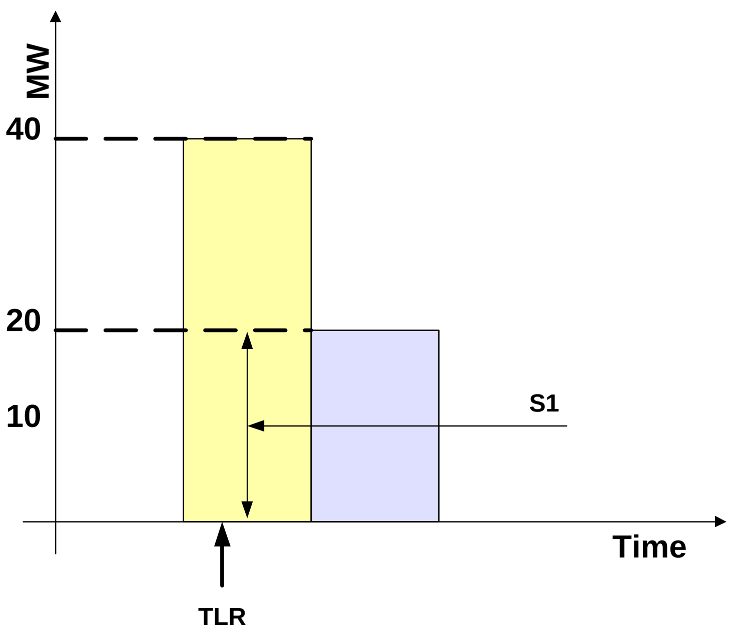
Energy Profile: Current hour	20 MW
Actual flow following curtailment: Current hour	20 MW (no curtailment)
Energy Profile: Next hour	40 MW



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

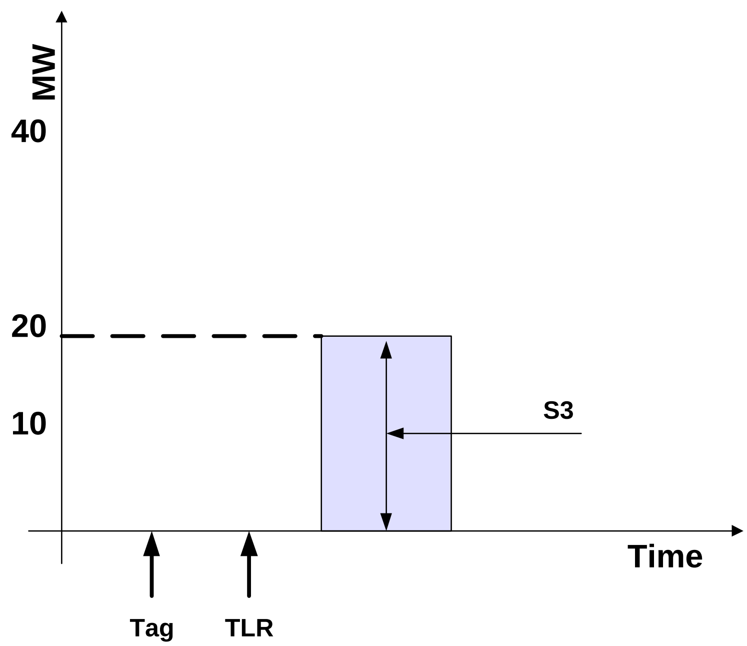


Sub-priorities for Transaction MW:

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



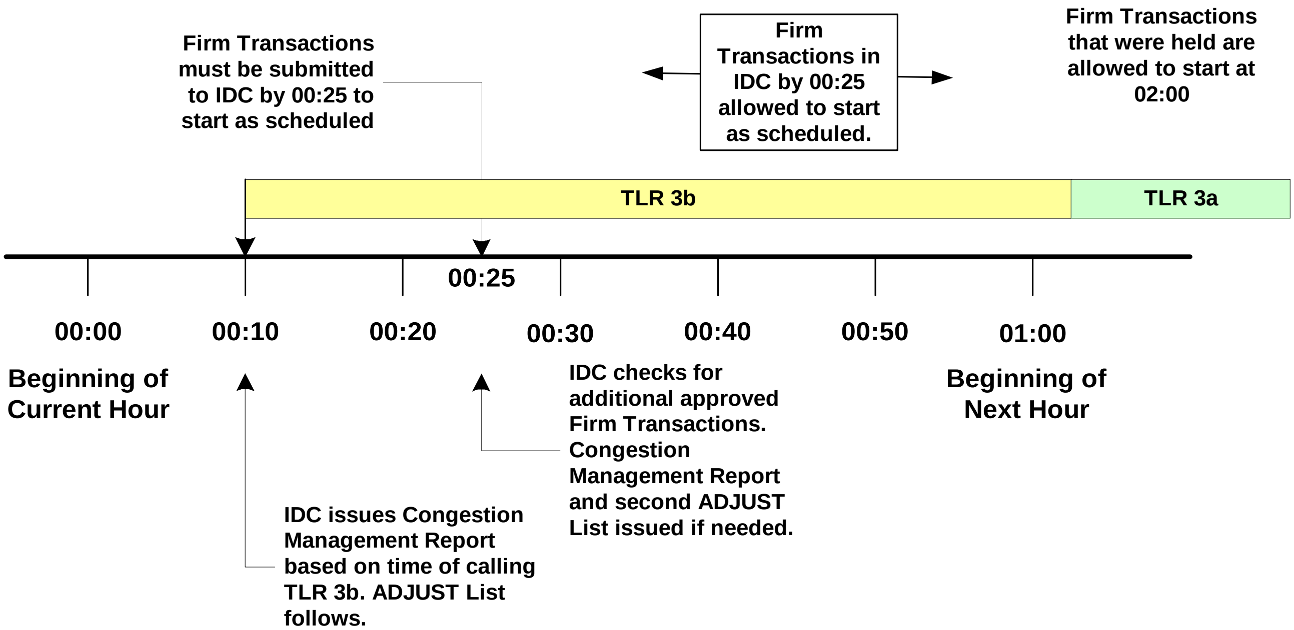
Sub-Priority	*MW Value*	*Explanation*
S1	0 MW	Transaction was not allowed to start
S2	+0 MW	Transaction was not allowed to start
S3	+20 MW	Next-hour Energy Profile is 20MW
S4	+0	Tag submitted prior to TLR

Appendix F. Considerations for Market Flows and Interchange Transactions

Using Firm Point-to-Point Transmission Service

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

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



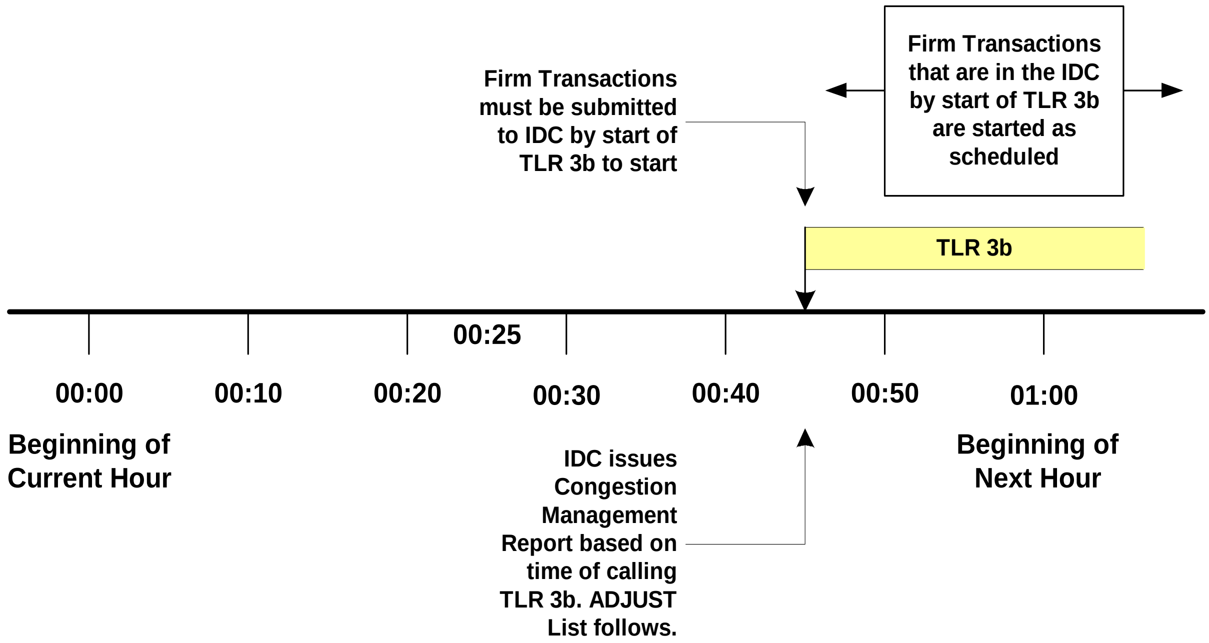
1. The IDC will examine the current hour (00) and next hour (01) for all Market Flows and Interchange Transactions.
2. The IDC will issue an ADJUST List based upon the time the TLR 3b is called. The ADJUST List will include curtailments of Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for Firm Market Flows and those Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled.
3. At 00:25, the IDC will check for additional Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by that time and issue a second ADJUST List if those additional Interchange Transactions are found.
4. All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.
5. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled.
6. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC after 00:25 will be held.

7. Once the SOL or IROL violation is mitigated, the Reliability Coordinator shall call a TLR Level 3a (or lower). If a TLR Level 3a is called:

    a. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled at 02:00.

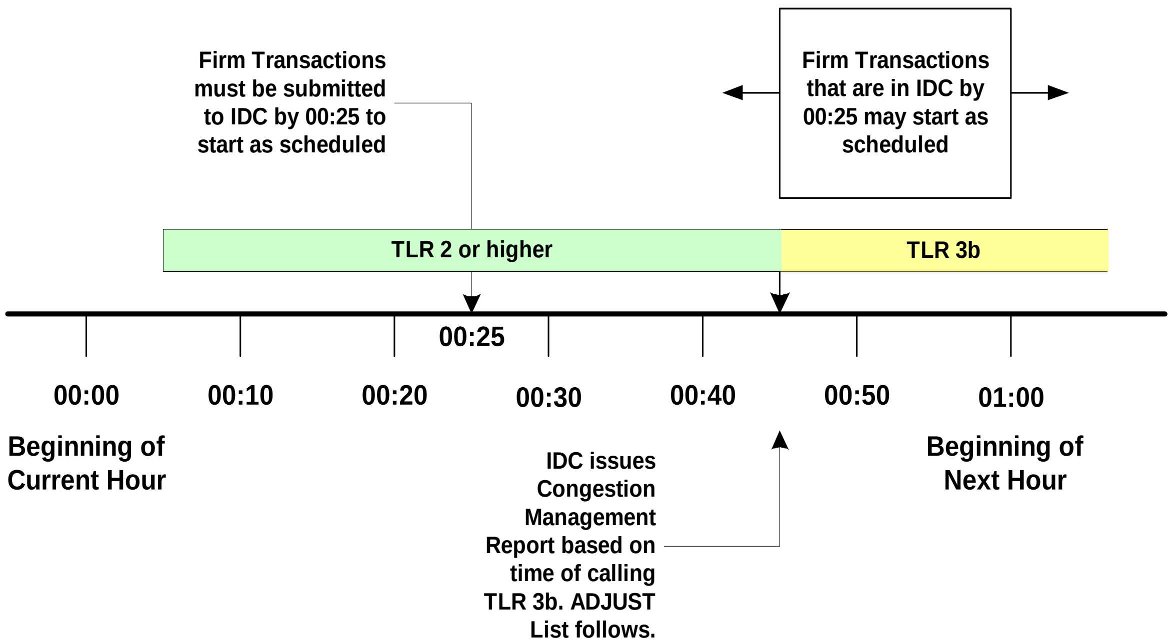
    b. Interchange Transactions using Non-firm Point-to-Point Transmission Service that were held may then be reallocated to start at 02:00.

Case 2: TLR 3b is called after 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC no later than the time at which the TLR 3b is called.



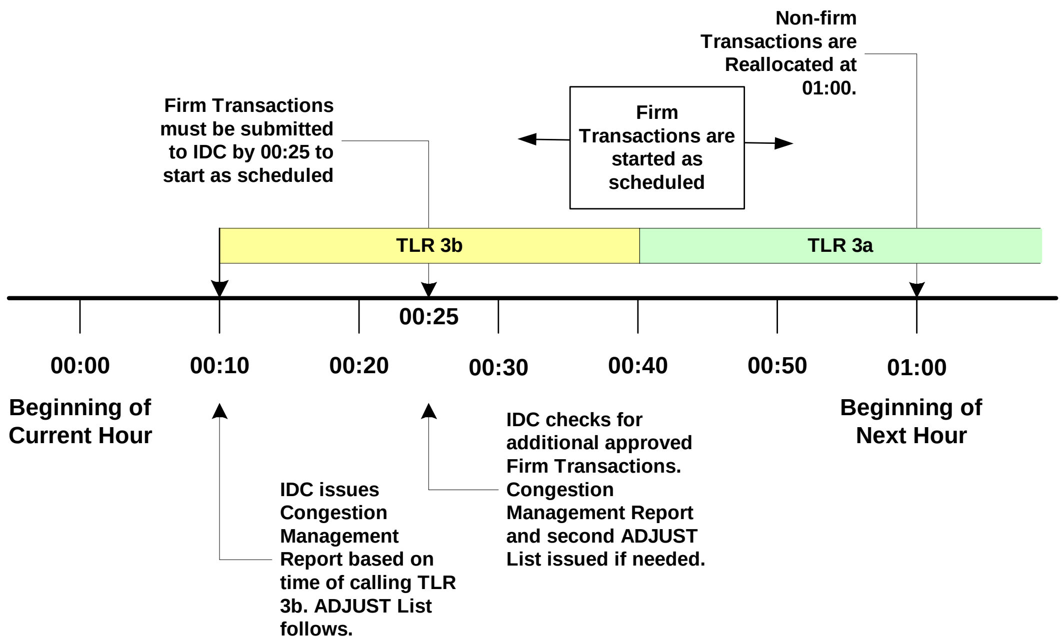
1. The IDC will examine the current hour (00) and next hour (01) for all Market Flows and Interchange Transactions.
2. The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Non-firm Market Flows and Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for Firm Market Flows and those Interchange Transactions using Firm Point-to-Point Transmission Service to start at as scheduled.
3. All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.
4. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by the time the TLR 3b was called will be allowed to start at as scheduled.
5. Interchange Transaction using Firm Point-to-Point Transmission Service that were submitted to the IDC after the TLR 3b was called will be held until the next issuance for TLR (either TLR 3b, 3a, or lower level).

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



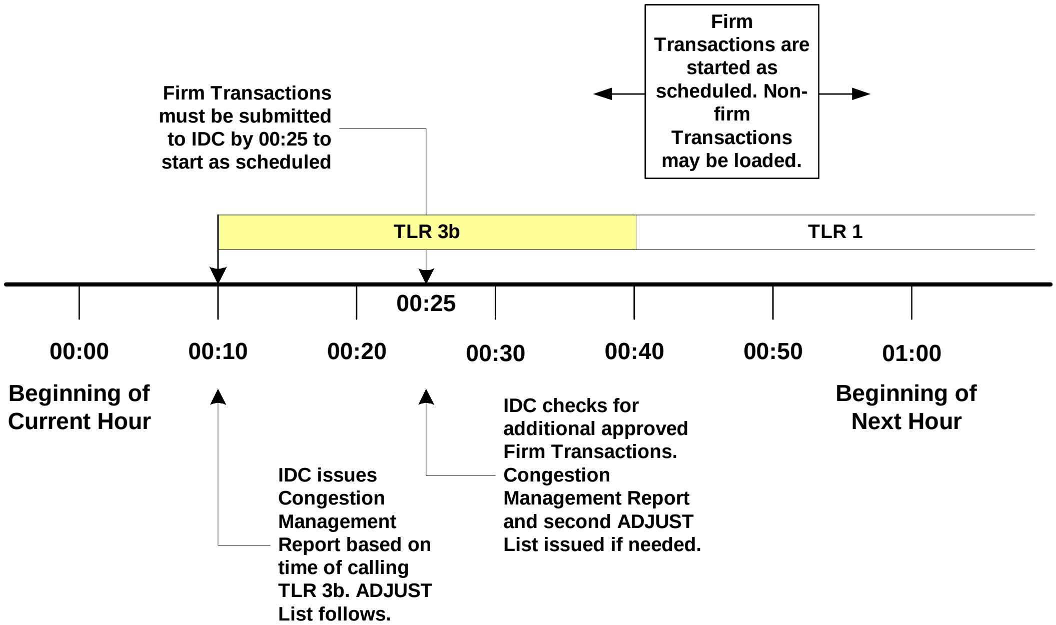
If a TLR 2 or higher has been issued and 3B is subsequently issued, then only Firm Market Flows and those Interchange Transactions using Firm Point-to-Point Transmission Service that had been submitted to the IDC by 00:25 will be allowed to start as scheduled. All other Interchange Transactions are held.

Case 4. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 3a is called at 00:40.



1. Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 3a.
2. Firm Market Flows and all Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled if in by the time the 3A is declared.
3. Non-firm Market Flows and all Interchange Transactions using Non-firm Point-to-Point Transmission Service are reallocated at 01:00.

Case 5. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 1 is called at 00:40.



1. Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 1.
2. Firm Market Flows and all Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled.
3. Non-firm Market Flows and all Interchange Transactions using Non-firm Point-to-Point Transmission Service may be loaded immediately.

Appendix G. Examples of On-Path and Off-Path Mitigation

Examples

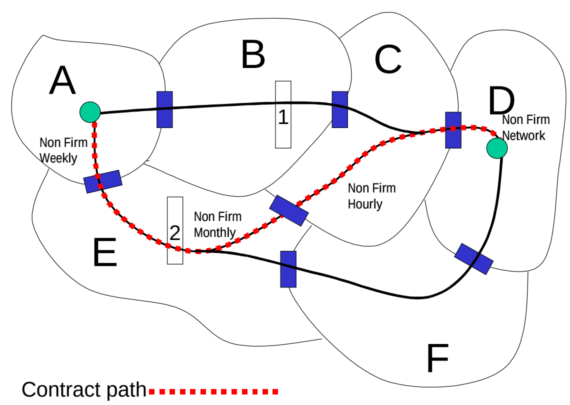
This section explains, by example, the obligations of the Transmission Service Providers on and off the Contract Path when calling for Transmission Loading Relief. (References to Principles refer to **Requirement 4, "Mitigating Constraints On and Off the Contract Path during TLR**," on the preceding pages.) When Reallocating or curtailing Interchange Transactions using Firm Point-to-Point Transmission Service under TLR Level 5a or 5b, the Transmission Service Providers may be obligated to perform comparable curtailments of its Transmission Service to Network Integration and Native Load customers. See **Requirement 5, "Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service during TLR**."

Scenario:

- Interchange Transaction arranged from system A to system D, and assumed to be at or above the Curtailment Threshold.
- Contract path is A-E-C-D (except as noted).
- Locations 1 and 2 denote Constraints.

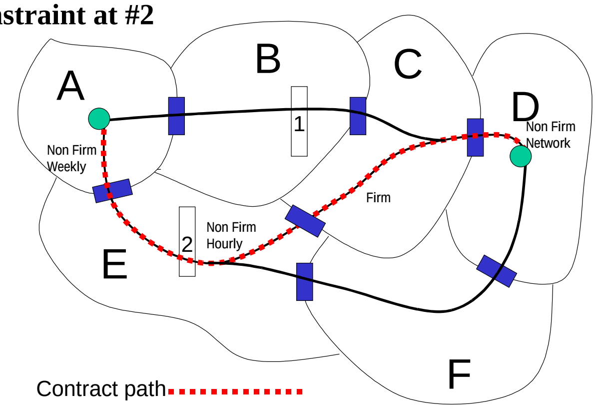
Case 1: E is a non-firm Monthly path; C is non-firm Hourly; E has Constraint at #2

- E may call its Reliability Coordinator for TLR to relieve overload at Constraint #2.
- Interchange Transaction A-D may be curtailed by TLR action **as though it was being served by Non-firm Monthly Point-to-Point Transmission Service**, even though it was using Non-firm Hourly Point-to-Point Transmission Service from C. That is, it takes on the priority of the link with the Constrained Facility along the Contract Path (Principle 1).

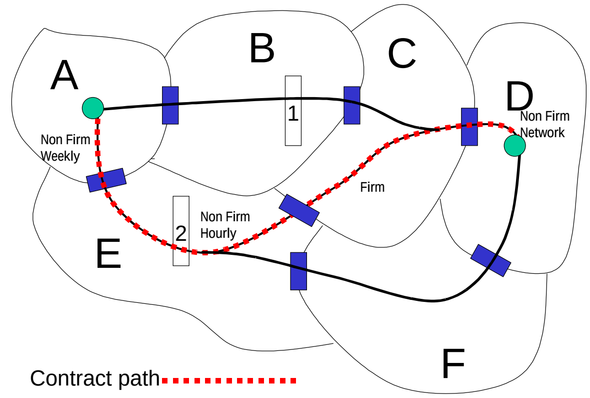


Case 2: E is a non-firm hourly path, C is firm; E has Constraint at #2

- Although C is providing Firm Service, the Constraint is not on C's system; therefore E is not obligated to treat the Interchange Transaction as though it was being served by Firm Point-to-Point Transmission Service.
- E may call its Reliability Coordinator for TLR to relieve overload at Constraint #2.
- Interchange Transaction A-D may be curtailed by TLR action as though it was being served by Non-firm Hourly Point-to-Point Transmission Service, even though it was using firm service from C. That is, when the constraint is on the Contract Path, the Interchange Transaction takes on the priority of the link with the Constrained Facility (Principle 1).

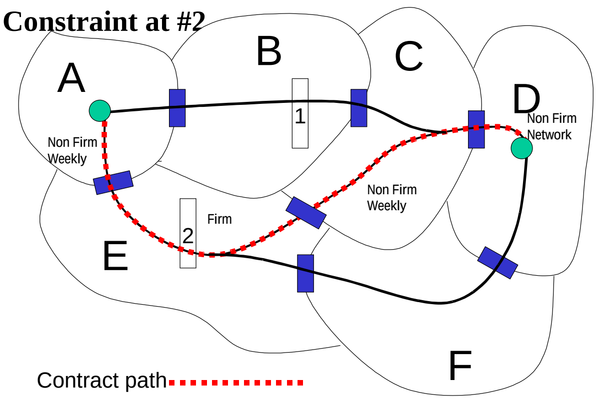


Case 3: E is a non-firm hourly path, C is firm, B has Constraint at #1



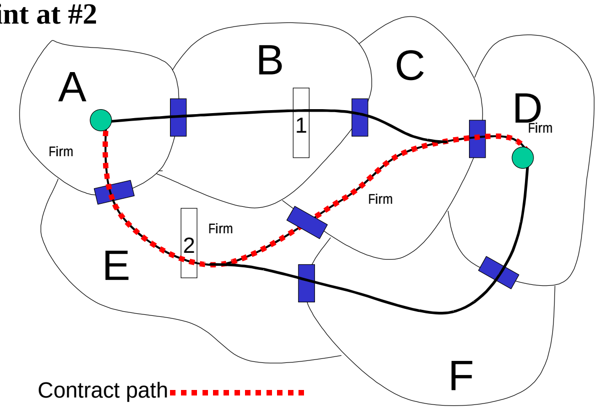
- B may call its Reliability Coordinator for TLR to relieve overload at Constraint #1.
- Interchange Transaction A-D may be curtailed by TLR action as though it was being served by Non-firm Hourly Transmission Service, even if it was using firm Transmission Service elsewhere on the path. When the constraint is off the Contract Path, the Interchange Transaction takes on the lowest priority reserved on the Contract Path (Principle 3).

Case 4: E is a firm path; A, D, and C are Non-firm; E has Constraint at #2



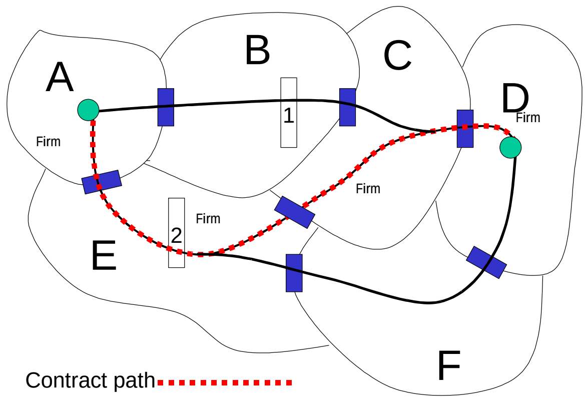
- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may then call its Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-firm Point-to-Point Transmission Service first.
- E is obligated to try to reconfigure transmission to mitigate Constraint #2 in E before E may curtail the Interchange Transaction as ordered by the TLR (Principle 2).

Case 5: The entire path (A-E-C-D) is firm; E has Constraint at #2



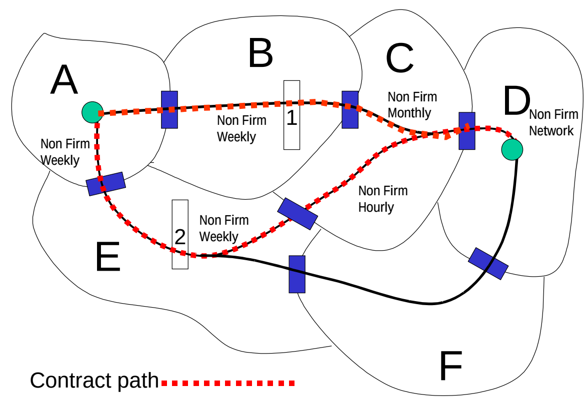
- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may call its Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-firm Point-to-Point Transmission Service first.
- E is obligated to curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service, and then reconfigure transmission on its system, or, if there is an agreement in place, arrange for reconfiguration or other congestion management options on another system, to mitigate Constraint #2 in E before the firm A-D transaction is curtailed (Principle 2).
- A, C, D, may be requested by E to try to reconfigure transmission to mitigate Constraint #2 in E at E's expense (Principle 2).

Case 6: The entire path (A-E-C-D) is firm; B has Constraint at #1.



- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- B may call its Reliability Coordinator for TLR for all *non-firm* Interchange Transactions that contribute to the overload at Constraint #1.
- Following the curtailment of all non-firm Interchange Transactions, the Reliability Coordinator (ies) will determine which Transmission Operator(s) will reconfigure their transmission, if possible, to mitigate constraint #1 (Principle 4).
- A-D transaction may be curtailed as a result. However, the A-D transaction is treated as a firm Interchange Transaction and will be curtailed only after non-firm Interchange Transactions. (Note: This means that the firm Contract Path is respected by all parties, including those not on the Contract Path.) (Principle 4)

Case 7: Two A-to-D transactions using A-B-C-D and A-E-C-D; A and B are non-firm; B has Constraint at #1



- B is not obligated to reconfigure transmission to mitigate Constraint at #1. (Principle 1)
- B may call its Reliability Coordinator for TLR to relieve overload at Constraint #1.
- If both A – D Interchange Transactions have the same Transfer Distribution Factors across Constraint #1, then they both are subject to curtailment. However, Interchange Transaction A – D using the A-B-C-D path is assigned a higher priority (priority NW on B), and would not be curtailed until after the Interchange Transaction using the path A-E-C-D (priority NH on the Contract Path as observed by B who is off the Contract Path).

A. Introduction

1. Title: **Disturbance Reporting**

2. Number: EOP-004-0

3. Purpose: Disturbances or unusual occurrences that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions, need to be studied and understood to minimize the likelihood of similar events in the future.

4. Applicability

4.1. Reliability Coordinators.

4.2. Balancing Authorities.

4.3. Transmission Operators.

4.4. Generator Operators.

4.5. Load Serving Entities.

4.6. Regional Reliability Organizations.

5. Effective Date: April 1, 2005

B. Requirements

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

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

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

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

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

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

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

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

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

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

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

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

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

Introduction

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

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

1. The loss of a bulk power transmission component that significantly affects the integrity of interconnected system operations. Generally, a disturbance report will be required if the event results in actions such as:
   a. Modification of operating procedures.
   b. Modification of equipment (e.g. control systems or special protection systems) to prevent reoccurrence of the event.
   c. Identification of valuable lessons learned.
   d. Identification of non-compliance with NERC standards or policies.
   e. Identification of a disturbance that is beyond recognized criteria, i.e. three-phase fault with breaker failure, etc.
   f. Frequency or voltage going below the under-frequency or under-voltage load shed points.
2. The occurrence of an interconnected system separation or system islanding or both.
3. Loss of generation by a Generator Operator, Balancing Authority, or Load-Serving Entity — 2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection.
4. Equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below:
   a. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
   b. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.
5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.
6. Any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in:
   a. Sustained voltage excursions equal to or greater than ±10%, or
   b. Major damage to power system components, or

   c. Failure, degradation, or misoperation of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require operator intervention, which did result in, or could have resulted in, a system disturbance as defined by steps 1 through 5 above.

7. An Interconnection Reliability Operating Limit (IROL) violation as required in reliability standard TOP-007.
8. Any event that the Operating Committee requests to be submitted to Disturbance Analysis Working Group (DAWG) for review because of the nature of the disturbance and the insight and lessons the electricity supply and delivery industry could learn.

NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report

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

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

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

Introduction

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

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

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

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

The initial DOE Electric Emergency Incident and Disturbance Report (form OE-417 – Schedule 1 – Emergency Alert Notice) shall be submitted to the DOE Operations Center within 60 minutes of the time of the system disruption if one of the following apply:

1. Actual physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations
2. Actual cyber or communications attack that causes major interruptions of electrical system operations

3. Complete operational failure or shut-down of the transmission and/or distribution electrical system
4. Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system
5. Uncontrolled loss of 300 Megawatts (MW) or more of firm system loads for more than 15 minutes from a single incident
6. Load shedding of 100 MW or more implemented under emergency operational policy
7. System-wide voltage reductions of 3 percent or more
8. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system

The initial DOE Electric Emergency Incident and Disturbance Report (form OE-417 – Schedule 1~~–~~— Normal Alert Notice) shall be submitted to the DOE Operations Center within six hours of the time of the system disruption if one of the following apply and none of the eight categories above apply:

9. Suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism which targets components of any security systems
10. Suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability
11. Loss of electric service to more than 50,000 customers for 1 hour or more
12. Fuel supply emergencies that could impact electric power system adequacy or reliability.

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

~~The initial DOE Emergency Incident and Disturbance Report (form EIA-417 – Schedule 1) shall be submitted to the DOE Operations Center within 60 minutes of the time of the system disruption.~~ Complete information may not be available at the time of the disruption. However, provide as much information as is known or suspected at the time of the initial filing. If the incident is having a critical impact on operations, a telephone notification to the DOE Operations Center (202-586-8100) is acceptable, pending submission of the completed form OE~~EIA~~-417. Electronic submission via an on-line web-based form is the preferred method of notification. However, electronic submission by facsimile or email is acceptable.

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

Table 1-EOP-004-0
Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies

Incident No.	Incident	Threshold	Report Required	Time
1	Actual physical attack	Major Interruptions or impact to critical infrastructure or operations	Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
2	Actual cyber or communications attack	Major interruptions of electrical system operations	Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
3	Complete operational failure or shut-down of the transmission and/or distribution electrical system		Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
4	Electrical System Separation (Islanding)		Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
5	Uncontrolled loss of load	≥300 Megawatts firm system loads > 15 minutes from a single incident	Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
6	Load shedding	≥100 MW	Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
7	System-wide voltage reductions	≥3 percent	Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
8	Public appeal to reduce the use of electricity		Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
9	Suspected physical attacks	Impact electric power system adequacy or reliability; or vandalism which targets components of any security systems	Form OE-417 Schedule 1—Alert Notice	6 hours 48 hours
10	Suspected cyber or communications attacks	impact electric power system adequacy or vulnerability	Form OE-417 Schedule 1—Alert Notice	6 hours 48 hours
11	Loss of electric service	≥50,000 customers ≥1 hour	Form OE-417 Schedule 1—Alert Notice	6 hours 48 hours
12	Fuel supply emergencies	Could impact electric power system adequacy or	Form OE-417 Schedule 1—Alert Notice	6 hours 48 hours

		reliability		

~~Table 1-EOP-004-0~~

~~Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies~~

~~Incident No.~~	~~Incident~~	~~Threshold~~	~~Report Required~~	~~Time~~
~~1~~	~~Uncontrolled loss of Firm System Load~~	~~≥ 300 MW – 15 minutes or more~~	~~EIA – Sch-1~~ ~~EIA – Sch-2~~	~~1 hour~~ ~~48 hour~~
~~2~~	~~Load Shedding~~	~~≥ 100 MW under emergency operational policy~~	~~EIA – Sch-1~~ ~~EIA – Sch-2~~	~~1 hour~~ ~~48 hour~~
~~3~~	~~Voltage Reductions~~	~~3% or more – applied system-wide~~	~~EIA – Sch-1~~ ~~EIA – Sch-2~~	~~1 hour~~ ~~48 hour~~
~~4~~	~~Public Appeals~~	~~Emergency conditions to reduce demand~~	~~EIA – Sch-1~~ ~~EIA – Sch-2~~	~~1 hour~~ ~~48 hour~~
~~5~~	~~Physical sabotage, terrorism or vandalism~~	~~On physical security systems – suspected or real~~	~~EIA – Sch-1~~ ~~EIA – Sch-2~~	~~1 hour~~ ~~48 hour~~
~~6~~	~~Cyber sabotage, terrorism or vandalism~~	~~If the attempt is believed to have or did happen~~	~~EIA – Sch-1~~ ~~EIA – Sch-2~~	~~1 hour~~ ~~48 hour~~
~~7~~	~~Fuel supply emergencies~~	~~Fuel inventory or hydro storage levels ≤ 50% of normal~~	~~EIA – Sch-1~~ ~~EIA – Sch-2~~	~~1 hour~~ ~~48 hour~~
~~8~~	~~Loss of electric service~~	~~≥ 50,000 for 1 hour or more~~	~~EIA – Sch-1~~ ~~EIA – Sch-2~~	~~1 hour~~ ~~48 hour~~
~~9~~	~~Complete operation failure of electrical system~~	~~If isolated or interconnected electrical systems suffer total electrical system collapse~~	~~EIA – Sch-1~~ ~~EIA – Sch-2~~	~~1 hour~~ ~~48 hour~~

~~All DOE EIA-417 Schedule 1 reports are to be filed within 60-minutes after the start of an incident or disturbance~~
~~All DOE EIA-417 Schedule 2 reports are to be filed within 48-hours after the start of an incident or disturbance~~

Table 1-EOP-004-0

Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies

OE- 417 - Schedule 1 – Emergency Alert Notice

Incident No.	Incident	Threshold	Report Required	Time
1	Actual physical attack	Major Interruptions or impact to critical infrastructure or operations	Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
2	Actual cyber or communications attack	Major interruptions of electrical system operations	Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
3	Complete operational failure or shut-down of the transmission and/or distribution electrical system		Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
4	Electrical System Separation (Islanding)		Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
5	Uncontrolled loss of load	≥300 Megawatts firm system loads > 15 minutes from a single incident	Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
6	Load shedding	≥100 MW	Form OE-417 Schedule	1 hour

			1—Alert Notice	48 hours
7	System-wide voltage reductions	≥3 percent	Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
8	Public appeal to reduce the use of electricity		Form OE-417 Schedule 1—Alert Notice	1 hour 48 hours
OE-417 - Schedule 1 – Normal Alert				
9	Suspected physical attacks	Impact electric power system adequacy or reliability; or vandalism which targets components of any security systems	Form OE-417 Schedule 1—Alert Notice	6 hours 48 hours
10	Suspected cyber or communications attacks	impact electric power system adequacy or vulnerability	Form OE-417 Schedule 1—Alert Notice	6 hours 48 hours
11	Loss of electric service	≥50,000 customers ≥1 hour	Form OE-417 Schedule 1—Alert Notice	6 hours 48 hours
12	Fuel supply emergencies	Could impact electric power system adequacy or reliability	Form OE-417 Schedule 1—Alert Notice	6 hours 48 hours

All entities required to file a DOE ~~EIA~~OE-417 report (Schedule 1 & 2) shall send a copy of these reports to NERC simultaneously, but no later than 24 hours after the start of the incident or disturbance.

Incident No.	Incident	Threshold	Report Required	Time
1	Loss of major system component	Significantly affects integrity of interconnected system operations	NERC Prelim Final report	24 hour 60 day
2	Interconnected system separation or system islanding	Total system shutdown Partial shutdown, separation, or islanding	NERC Prelim Final report	24 hour 60 day
3	Loss of generation	≥ 2,000 – Eastern Interconnection ≥ 2,000 – Western Interconnection ≥ 1,000 – ERCOT Interconnection	NERC Prelim Final report	24 hour 60 day
4	Loss of firm load ≥15-minutes	Entities with peak demand ≥3,000: loss ≥300 MW All others ≥200MW or 50% of total demand	NERC Prelim Final report	24 hour 60 day
5	Firm load shedding	≥100 MW to maintain continuity of bulk system	NERC Prelim Final report	24 hour 60 day
6	System operation or operation actions resulting in:	• Voltage excursions ≥10% • Major damage to system components • Failure, degradation, or misoperation of SPS	NERC Prelim Final report	24 hour 60 day
7	IROL violation	Reliability standard TOP-007.	NERC Prelim Final report	72 hour 60 day
8	As requested by ORS Chairman	Due to nature of disturbance & usefulness to industry (lessons learned)	NERC Prelim Final report	24 hour 60 day

All NERC Operating Security Limit and Preliminary Disturbance reports will be filed within 24 hours after the start of the incident. If an entity must file a DOE ~~EIA~~OE-417 report on an incident, which requires a NERC Preliminary report, the Entity may use the DOE ~~EIA~~OE-417 form for both DOE and NERC reports.

Any entity reporting a DOE or NERC incident or disturbance has the responsibility to also notify its Regional Reliability Organization.

When completed, e-mail to: mark.ladrow@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	EOP-004-1
Request Date	12/19/2005

SAR Requestor Information	**SAR Type** (Put an 'x' in front of one of these selections)	
Name John Theotonio	☐	New Standard
Primary Contact John Theotonio	☒	Revision to existing Standard
Telephone 609 452 8060 Fax 609 452 9550	☐	Withdrawal of existing Standard
E-mail john.theotonio@nerc.net	☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

The United States Department of Energy (DOE) recently superceded form EIA-417 with OE-417. The Attachments to EOP-004-0 Disturbance Reporting include reference and text from EIA-417 as well as mirroring some of the reporting requirements included in EIA-417. The standard needs to be modified to reflect the new DOE OE-417.

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
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐	Transmission Owner	Owns transmission facilities
☒	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☒	Generator	Owns and operates generation unit(s) or runs a market for generation products that performs the functions of supplying energy and interconnected operations services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity, and all necessary interconnected operations services as required
☒	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

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

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box 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

Scope (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)
The United States Department of Energy (DOE) recently superceded form EIA-417 with OE-417. The Attachments to EOP-004-0 Disturbance Reporting include reference and text from EIA-417 as well as mirroring some of the reporting requirements included in EIA-417. EOP-004-0 needs to be modified to reflect the new DOE OE-417. The scope of the effort would be to modify the attachments (1&2) to EOP-004-0 to make them consistent with the new DOE OE-417.

Related Standards

Standard No.	Explanation
IRO-004-0	Attachments 1 and 2

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

R05004

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction
or
Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

Instructions:

1. Please fill out as much of the requested information as possible. It is mandatory to provide a contact name, phone number and fax number to which questions can be directed. If you have an electronic mailing address, please make that available as well.

2. Attach any information you believe is related to the request. The more complete your request is, the less time is required to review it.

3. Once completed, send your request to:

   Rae McQuade
   NAESB, Executive Director
   1301 Fannin, Suite 2350
   Houston, TX 77002

   Phone: 713-356-0060
   Fax: 713-356-0067

   by either mail, fax, or to NAESB's email address, naesb@naesb.org.

Once received, the request will be routed to the appropriate subcommittees for review.

Please note that submitters should provide the requests to the NAESB office in sufficient time so that the NAESB Triage Subcommittee may fully consider the request prior to taking action on it. It is preferable that the request be submitted a minimum of 3 business days prior to the Triage Subcommittee meetings. Those meeting schedules are posted on the NAESB web site at http://www.naesb.org/monthly_calendar.asp.

R05004

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction
or
Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

Date of Request: ___~~03-22-2005~~September 6, 2005_______________

1. Submitting Entity & Address:
   __**NERC ~~Long Term ATC/AFC Task Force (LTATF)~~ATCT SAR Drafing Team**__________

   ____

   ____

   ____

2. Contact Person, Phone #, Fax #, Electronic Mailing Address:
   Name : ______________________________
   Title : ______________________________
   Phone : ______________________________
   Fax : ______________________________
   E-mail : _**ltatf@nerc.com**____________________

3. Description of Proposed Standard or Enhancement:
   It is proposed that a single Business Practice Standard be developed related to both:

   1) the processing ~~and evaluation~~appraisal of transmission service requests, which use TTC/ATC/AFC and CBM/TRM

   2) the processing ~~and evaluation~~appraisal of request(s) to schedule against approved transmission service reservation(s).

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4. Use of Proposed Standard or Enhancement (include how the standard will be used, documentation on the description of the proposed standard, any existing documentation of the proposed standard, and required communication protocols):

   a. **The proposed standard will be applicable to transmission service providers to ensure that consistent practices are employed among transmission service providers when processing requests for transmission service,**

   ~~**b.The proposed standard will be applicable to transmission service providers to ensure that consistent scheduling practices are employed among transmission service providers, and**~~

   ~~**c.**~~**b. The proposed standard will be applicable to transmission service providers to ensure that details of the practices and procedures are available to market participants.**

5. Description of Any Tangible or Intangible Benefits to the Use of the Proposed Standard or Enhancement:

   Providing increased standardization of procedures and better informing market participants of these procedures would enhance market liquidity.

   Additionally, this should result in better utilization of the transmission system.

6. Estimate of Incremental Specific Costs to Implement Proposed Standard or Enhancement:

   t.b.d.

7. Description of Any Specific Legal or Other Considerations:

   Development of this Business Practice needs to be closely coordinated with any work undertaken by NERC that impacts the calculation and coordination of AFC/ATC.

   NERC's Long Term ATC/AFC TF (LTATF), which included NAESB participation, has identified a number of issues related to the calculation and coordination of ATC and AFC. Excerpts from the LTATF report are appended to the end of this document.

It is recommended that NAESB develop a Business Practice Standard that would ensure full disclosure ~~as well as standardization where possible of the methodology~~ by which Transmission Service Providers (TSPs) determine the quantity of transmission service to be made available for sale to market participants; and accept schedules for transmission previously purchased
~~:~~
~~- Determine the quantity of transmission service to be made available for sale to market participants; and~~
~~- Accept schedules for transmission previously purchased~~

In addition, in developing this methodology, each Transmission Service Provider TSP should, to the maximum extent possible ~~:~~
~~- Use similar models and assumptions within equivalent operating timeframes;~~
~~- Use models and assumptions for the sale of transmission service that are similar to those used for the planning of the transmission system;~~
~~- A~~assure comparability of service for long term firm point to point and network service customers;
~~- Assure appropriate coordination between TSPs such that the sale of transmission service by one provider appropriately reflects the impacts on affected systems.~~

8. If This Proposed Standard or Enhancement Is Not Tested Yet, List Trading Partners Willing to Test Standard or Enhancement (Corporations and contacts):

    N/A

9. If This Proposed Standard or Enhancement Is In Use, Who are the Trading Partners:

    N/A

10. Attachments (such as : further detailed proposals, transaction data descriptions, information flows, implementation guides, business process descriptions, examples of ASC ANSI X12 mapped transactions):

    Please see final Long Term AFC/ATC Task Force report on the NERC website at: www.nerc.com (need to update with full URL when available)

R05004

North American Energy Standards Board

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R05004

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction
or
Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

Date of Request: ___Revised December 12, 2005_______________

1. Submitting Entity & Address:
   __NERC ATCT SAR Drafing Team __________

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2. Contact Person, Phone #, Fax #, Electronic Mailing Address:

   Name : ___________________________________
   Title : ___________________________________
   Phone : ___________________________________
   Fax : ___________________________________
   E-mail : **_ltatf@nerc.com____________________**

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In addition, in developing this methodology, each Transmission Service Provider TSP should, to the maximum extent possible assure comparability of service for long term firm point to point and network service customers;

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