NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

September 11, 2006

<u>VIA OVERNIGHT MAIL</u>

James Hoffman
Crown Investments Corporation of Saskatchewan
400-2400 College Avenue
Regina, Saskatchewan
S4P 1C8

Re: *North American Electric Reliability Corporation*

Dear Mr. Hoffman:

The North American Electric Reliability Corporation ("NERC") hereby submits an Application for Recognition of Proposed Reliability Standards. In addition to the paper copy of the Notice, NERC is also submitting one CD containing a copy of the entire application. The record for the development of these standards is extensive (over 13,000 pages); NERC will supply an electronic copy of the developmental record upon request. NERC requests, to the extent necessary, a waiver of any applicable filing requirements with respect to the filing of this notice.

Please contact the undersigned if you have any questions.

Respectfully submitted,

___/s/ Rick Sergel_____
Richard P. Sergel
President and Chief Executive Officer
David N. Cook

Vice President and General Counsel
North American Electric Reliability Corp.
116-390 Village Boulevard
Princeton, NJ 08540-5731
(609) 452-8060
(609) 452-9550 – facsimile
rick.sergel@nerc.net
david.cook@nerc.net

Enclosures

BEFORE THE
CROWN INVESTMENT CORPORATION
OF THE PROVINCE OF SASKATCHEWAN

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

NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL AND NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF PROPOSED RELIABILITY STANDARDS

The North American Electric Reliability Council, on behalf of its affiliate, the North American Electric Reliability Corporation,[1] hereby submits this Notice of Filing of the proposed 16 new and 11 revised reliability standards set out in **Exhibit A**. Several of these standards, as noted in this filing, modify or replace standards contained in NERC's April 4, 2006 filing of the initial set of 102 standards.

NERC has filed these reliability standards with the Federal Energy Regulatory Commission ("FERC") and is also filing them with the other relevant governmental authorities in Canada.

[1] The North American Electric Reliability Council ("NERC Council") has formed an affiliate, the North American Electric Reliability Corporation ("NERC Corporation") to serve as the electric reliability organization authorized by Section 215 of the Federal Power Act. These organizations may be separately or collectively referred to herein as "NERC". On July 20, 2006, the Federal Energy Regulatory Commission certified NERC Corporation as the electric reliability organization within the U.S.

Richard P. Sergel
President and Chief Executive Officer
David N. Cook
Vice President and General Counsel
North American Electric Reliability Council
116-390 Village Boulevard
Princeton, NJ 08540-5731
(609) 452-8060
(609) 452-9550 – facsimile
rick.sergel@nerc.net
david.cook@nerc.net

September 11, 2006

Table of Contents

Background:

Basis for Filing of Additional Proposed Reliability Standards

While in the current state of transition toward becoming a fully functional ERO with enforceable reliability standards, NERC is continuing on an aggressive pace to develop new and revised standards that address the issues we identified in our initial filing of proposed standards in April 2006. The proposed reliability standards presented in **Exhibit A** address a number of these issues, as will be detailed in this Notice of Filing, while work continues on the remaining issues. These proposed standards have been developed and approved by industry stakeholders using NERC's standards development procedure, and have been approved by the NERC Board of Trustees for filing with this Province.[2]

Reliability Standards Development Procedure

In its Notice of Filing to be certified as the ERO, NERC explained that reliability standards would be developed in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Reliability Standards Development Procedure, which was incorporated into the Rules of Procedure as Appendix A. The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders and a vote of stakeholders is required to approve a reliability standard.

Standards development requires progressive and continuous improvement. NERC is preparing a long-term plan for improvement of the standards, for filing later in 2006. NERC will

[2] The NERC board approved a portion of the standards in May 2006 and the remaining standards in August 2006. Filing of the proposed standards has been timed to allow NERC to evaluate the impact of the FERC staff preliminary assessment of the initial set of standards filed by NERC on April 4, 2006 and the ERO Certification Order. NERC intends that filing of proposed standards in the future will be made without delay and within 30 calendar days of NERC board action.

also, as part of the ERO budget process, develop annual work plans for standards development to manage near-term targets. The 2007 standards work plan has been filed separately with the proposed ERO budget. NERC proposes to periodically review these annual and long-term standards development plans with the relevant governmental authorities, and provide timely progress reports.

A key element of the work plan is to review and upgrade all existing standards based on actual experience. NERC's rules, and a condition of accreditation by the American National Standards Institute, require that each standard be reviewed at least every five years. NERC anticipates completing the review and upgrade of all standards over a three-year period, beginning with the highest priority standards in 2007. NERC's standards development procedure provides a systematic approach to improving the standards and documenting the basis for those improvements, and should serve as the mechanism for achieving those improvements. The standards presented in **Exhibit A** are a step in that direction.

Proposed Reliability Standards

NERC provides notice of the following proposed reliability standards, as set out in **Exhibit A**.

1. Critical Infrastructure Protection (CIP) standards:

   1.a. CIP-002-1: Cyber Security — Critical Cyber Asset Identification (new).

   1.b. CIP-003-1: Cyber Security — Security Management Controls (new).

   1.c. CIP-004-1: Cyber Security — Personnel and Training (new).

   1.d. CIP-005-1: Cyber Security — Electronic Security Perimeter(s) (new).

   1.e. CIP-006-1: Cyber Security — Physical Security of Critical Cyber Assets (new).

   1.f. CIP-007-1: Cyber Security — Systems Security Management (new).

   1.g. CIP-008-1: Cyber Security — Incident Reporting and Response Planning (new).

   1.h. CIP-009-1: Cyber Security — Recovery Plans for Critical Cyber Assets (new).

Because of the complexity of improvements in security measures required to meet these new standards and the expansion of the requirements to cover bulk power system owners, operators, and users not previously covered by the interim cyber security standard, NERC proposes a phased schedule for implementing these eight standards. **Exhibit B** presents the plan and schedule for implementing the cyber security standards. The schedule requires that all reliability coordinators and those transmission operators and balancing authorities that were previously responsible for complying with the urgent action standard be compliant with the requirements in accordance with the schedule in Table 1 of **Exhibit B**. The remaining balancing authorities and transmission operators, as well as all transmission service providers are required to be compliant in accordance with the schedule in Table 2. Transmission owners, generator owners and operators, load-serving entities, and interchange authorities are to be compliant in accordance with the schedule in Table 3 in **Exhibit B**. Table 4 provides a schedule for all other bulk power system owners, operators, and users to whom the standards may become applicable at a future date.

As promised in the standards notice filed on April 4, 2006, the Urgent Action Cyber Security Standard (1200) was retired to the standards archives effective June 1, 2006 and is no longer in effect.

2. Interchange Scheduling and Coordination (INT) standards:

   2.a. INT-001-1 — Interchange Information (revised). This proposed standard supersedes INT-001-0 that was filed in our April 4, 2006, filing. Requirements R1 and R2 have been modified and requirements R3, R4, and R5 are deleted because they are being replaced by requirements in other standards below.[3]

   2.b. INT-003-1 — Interchange Transaction Implementation (revised). This proposed standard supersedes INT-003-0 that was filed in our April 4, 2006, filing. Requirement R1 has been modified and requirements R2, R3, R4, R5, and R6 are deleted because they are being replaced by requirements in other standards below.

   2.c. INT-004-1 — Dynamic Interchange Transaction Modifications (revised). This proposed standard supersedes INT-004-0 that was filed in our April 4, 2006, filing. Requirements R1, R2, and R3 have been deleted because they are being replaced by requirements in other standards below and requirement R4 has been renumbered to become R1.

[3] Exhibit A-1 is a redline version of the revised reliability standards showing what changes were made.

2.d. INT-005-1 — Interchange Authority Distributes Arranged Interchange (new).

2.e. INT-006-1 — Response to Interchange Authority (new).

2.f. INT-007-1 — Interchange Confirmation (new).

2.g. INT-008-1 — Interchange Authority Distributes Status (new).

2.h. INT-009-1 — Implementation of Interchange (new).

2.i. INT-010-1 — Interchange Coordination Exceptions (new).

INT-002-0 — Interchange Transaction Tag Communication and Assessment is being retired effective January 1, 2007 and the standard will be placed in the standards archives on that date. The notice of filing of INT-002-0 filed on April 4, 2006, is hereby withdrawn.

3. Emergency Preparedness and Operations (EOP) standard:

3.a. EOP-005-1 — System Restoration Plans (revised). This proposed standard supersedes EOP-005-0 that was filed in our April 4, 2006, filing. Requirements R8 and R9 have been added as new. Previous requirements R8 and R9 have been revised and renumbered as requirements R10 and R11 respectively.

4. Modeling, Data, and Analysis (MOD) standards:

4.a. MOD-013-1 — Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedure (revised). This proposed standard supersedes MOD-013-0 that was filed in our April 4, 2006, filing. Requirements R8 and R9 have been added as new. Previous requirements R8 and R9 have been revised and renumbered as requirements R10 and R11 respectively.

4.b. Approve MOD-016-1 — Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management (revised). This proposed standard supersedes MOD-016-0 that was filed in our April 4, 2006, filing. Requirements R8 and R9 have been added as new. Previous requirements R8 and R9 have been revised and renumbered as requirements R10 and R11 respectively.

5. Protection and Control (PRC) standards:

5.a. PRC-002-1 — Define Regional Disturbance Monitoring and Reporting Requirements (revised). This proposed standard supersedes PRC-002-0 that was filed in our April 4, 2006, filing. Both requirements in the original standard were substantially revised and four new requirements were added.

5.b. PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting (new).

6. Voltage and Reactive (VAR) and Transmission Operations (TOP) standards:

6.a. VAR-001-1 — Voltage and Reactive Control (revised). This proposed standard supersedes VAR-001-0 that was filed in our April 4, 2006, filing. Requirements R3, R4, and R11 have been added as new. Previous requirement R4 has been revised and renumbered as requirement R6. Previous requirements R3, R5, R6, R7, R8, and R10 have been renumbered to requirements R5, R7, R8, R9, R10, and R12 respectively. Previous requirement R9 has been deleted, as it is replaced by new requirements on generators in VAR-002-1.

6.b. VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules (new), to become effective on August 2, 2007.

6.c. TOP-002-1 — Normal Operations Planning (revised), proposed to become effective on August 2, 2007. This revision to requirement R14 is linked to coincide with the effective date of VAR-002-1. The prior version (TOP-002-0), if made effective by the Commission prior to August 2, 2007, should be in effect until replaced by TOP-002-1.

7. Interconnection Reliability and Operations (IRO) standard:

7.a. IRO-006-3 — Reliability Coordination — Transmission Loading Relief (revised). This proposed standard supersedes IRO-006-1 that was filed in our April 4, 2006 filing. IRO-006-3 incorporates two sets of changes. The Version 2 changes modify the Transmission Loading Relief Procedure itself to allow reallocation of interchange transactions at the top of the next hour, following a Level 3b curtailment. This revision was developed through the regular standards process. The Version 3 change, which was developed through the urgent action process, extends an existing variance that applies in the PJM Interconnection ("PJM") and the Midwest Independent Transmission System Operator ("MISO") to now also apply in the Southwest Power Pool ("SPP"). This variance would allow SPP to supply market flow values to the Interchange Distribution Calculator ("IDC") in lieu of interchange transaction tags. This variance is necessary for organized market operators in the Eastern Interconnection that operate with multiple balancing areas. Without the variance, the NERC standard would otherwise require that energy flows between the balancing areas be tagged as bilateral transactions and entered into the IDC as tagged transactions. Substitution of calculated market flows is a suitable technical alternative that achieves the same result, but allows each independent system operator to comply with its approved tariff and market operating protocols. Because the SPP variance was approved through an urgent action, it will expire on August 2, 2007, unless extended or made permanent. The PJM and MISO variances were approved with the Version 0 standard and would remain in effect until the standard is revised or replaced. The copy of IRO-006-3 in **Exhibit A** incorporates both the Version 2 and Version 3 changes.

8. Resource and Demand Balancing (BAL) standard:

8.a. BAL-006-1 — Inadvertent Interchange (revised). This revision extends an existing variance that applies in MISO to also apply in SPP. The variance allows an organized market operator with multiple balancing areas to manage the inadvertent interchange accounts of the member balancing areas as a single account for the market area, which achieves the same reliability result while recognizing the approved market tariff and market operating protocols do not utilize bilateral interchange among the member balancing areas within the market. Because the SPP variance was approved through an urgent action, it will expire on May 2, 2007, unless extended or made permanent. The MISO variance was approved with the Version 0 standard and would remain in effect until the standard is revised or replaced.

Summary Status of All Proposed Reliability Standards

The table below summarizes the status of all proposed reliability standards submitted by NERC (i.e., the proposed standards from the April 2006 filing and the instant filing).

Table 1 — Status of Proposed Reliability Standards Submitted

Number	Title	Fill-in-the Blank Requirements	Missing Compliance Elements	Status
	Glossary of Terms Used in Reliability Standards			Pending revision, filed September 2006

Number	Title	Fill-in-the Blank Requirements	Missing Compliance Elements	Status
BAL-001-0	Real Power Balancing Control Performance			Pending, filed April 2006
BAL-002-0	Disturbance Control Performance	R1		Pending, filed April 2006
BAL-003-0	Frequency Response and Bias		Yes	Pending, filed April 2006
BAL-004-0	Time Error Correction		Yes	Pending, filed April 2006
BAL-005-0	Automatic Generation Control		Yes	Pending, filed April 2006
BAL-006-0	Inadvertent Interchange		Yes	Replaced by BAL-006-1
BAL-006-1	Inadvertent Interchange		Yes	Pending, revision, filed September 2006
CIP-001-0	Sabotage Reporting		Yes	Pending, filed April 2006
CIP-002-1	Cyber Security — Critical Cyber Asset Identification			Pending, new filed September 2006
CIP-003-1	Cyber Security — Security Management Controls			Pending, new filed September 2006
CIP-004-1	Cyber Security — Personnel and Training			Pending, new filed September 2006
CIP-005-1	Cyber Security — Electronic Security Perimeter(s)			Pending, new filed September 2006
CIP-006-1	Cyber Security — Physical Security of Critical Cyber Assets			Pending, new filed September 2006
CIP-007-1	Cyber Security — Systems Security Management			Pending, new filed September 2006
CIP-008-1	Cyber Security — Incident Reporting and Response Planning			Pending, new filed September 2006
CIP-009-1	Cyber Security — Recovery Plans for Critical Cyber Assets			Pending, new filed September 2006
COM-001-0	Telecommunications		Yes	Pending, filed

Number	Title	Fill-in-the Blank Requirements	Missing Compliance Elements	Status
				April 2006
COM-002-1	Communications and Coordination		Yes	Pending, filed April 2006
EOP-001-0	Emergency Operations Planning			Pending, filed April 2006
EOP-002-1	Capacity and Energy Emergencies			Pending, filed April 2006
EOP-003-0	Load Shedding Plans		Yes	Pending, filed April 2006
EOP-004-0	Disturbance Reporting	R3.4	Yes	Pending, filed April 2006
EOP-005-0	System Restoration Plans			Replaced by EOP-005-1
EOP-005-1	System Restoration Plans			Pending revision, filed September 2006
EOP-006-0	Reliability Coordination - System Restoration	R1	Yes	Pending, filed April 2006
EOP-007-0	Establish, Maintain, and Document a Regional Blackstart Capability Plan			Pending, filed April 2006
EOP-008-0	Plans for Loss of Control Center Functionality			Pending, filed April 2006
EOP-009-0	Documentation of Blackstart Generating Unit Test Results	R1, R2		Pending, filed April 2006
FAC-001-0	Facility Connection Requirements	R1		Pending, filed April 2006
FAC-002-0	Coordination of Plans for New Facilities	R1.2		Pending, filed April 2006
FAC-003-1	Vegetation Management Program			Pending, filed April 2006
FAC-004-0	Methodologies for Determining Electrical Facility Ratings	R1		Replaced by FAC-008-1
FAC-005-0	Electrical Facility Ratings for System Modeling			Replaced by FAC-009-1
FAC-008-1	Facility Ratings Methodology			Pending, filed April 2006
FAC-009-1	Establish and Communicate Facility Ratings			Pending, filed April 2006
FAC-012-1	Transfer Capabilities Methodology			Pending, filed April 2006
FAC-013-1	Establish and Communicate Transfer			Pending, filed

Number	Title	Fill-in-the Blank Requirements	Missing Compliance Elements	Status
	Capabilities			April 2006
INT-001-0	Interchange Transaction Tagging		Yes	Replaced by INT-001-1
INT-001-1	Interchange Information		Yes	Pending revision, filed September 2006
INT-002-0	Interchange Transaction Tag Communication and Assessment		Yes	Retired.
INT-003-0	Interchange Transaction Implementation		Yes	Replaced by INT-003-1
INT-003-1	Interchange Transaction Implementation		Yes	Pending revision, filed September 2006
INT-004-0	Interchange Transaction Modifications		Yes	Replaced by INT-004-1
INT-004-1	Dynamic Interchange Transaction Modifications		Yes	Pending revision, filed September 2006
INT-005-1	Interchange Authority Distributes Arranged Interchange			Pending, new filed September 2006
INT-006-1	Response to Interchange Authority			Pending, new filed September 2006
INT-007-1	Interchange Confirmation			Pending, new filed September 2006
INT-008-1	Interchange Authority Distributes Status			Pending, new filed September 2006
INT-009-1	Implementation of Interchange			Pending, new filed September 2006
INT-010-1	Interchange Coordination Exceptions			Pending, new filed September 2006
IRO-001-0	Reliability Coordination – Responsibilities and Authorities[1]			Pending, filed April 2006
IRO-002-0	Reliability Coordination – Facilities		Yes	Pending, filed April 2006
IRO-003-1	Reliability Coordination – Wide Area View		Yes	Pending, filed April 2006

Number	Title	Fill-in-the Blank Requirements	Missing Compliance Elements	Status
IRO-004-1	Reliability Coordination - Operations Planning			Pending, filed April 2006
IRO-005-1	Reliability Coordination – Current Day Operations	R14	Yes	Pending, filed April 2006
IRO-006-1	Reliability Coordination – Transmission Loading Relief			Replaced by IRO-006-3
IRO-006-3	Reliability Coordination — Transmission Loading Relief			Pending revision, filed September 2006
IRO-014-1	Procedures to Support Coordination Between Reliability Coordinators			Pending, filed April 2006
IRO-015-1	Notifications and Information Exchange Between Reliability Coordinators			Pending, filed April 2006
IRO-016-1	Coordination of Real-time Activities Between Reliability Coordinators			Pending, filed April 2006
MOD-001-0	Documentation of TTC and ATC Calculation Methodologies	R1		Pending, filed April 2006
MOD-002-0	Review of TTC and ATC Calculations and Results	R1		Pending, filed April 2006
MOD-003-0	Procedure for Input on TTC and ATC Methodologies and Values			Pending, filed April 2006
MOD-004-0	Documentation of Regional CBM Methodologies	R1		Pending, filed April 2006
MOD-005-0	Procedure for Verifying CBM Values	R1		Pending, filed April 2006
MOD-006-0	Procedures for Use of CBM Values			Pending, filed April 2006
MOD-007-0	Documentation of the Use of CBM			Pending, filed April 2006
MOD-008-0	Documentation and Content of Each Regional TRM Methodology	R1		Pending, filed April 2006
MOD-009-0	Procedure for Verifying TRM Values	R1		Pending, filed April 2006
MOD-010-0	Steady-State Data for Transmission System Modeling and Simulation	R1, R2		Pending, filed April 2006
MOD-011-0	Regional Steady-State Data Requirements and Reporting Procedures			Pending, filed April 2006
MOD-012-0	Dynamics Data for Transmission System Modeling and Simulation	R1, R2		Pending, filed April 2006

Number	Title	Fill-in-the Blank Requirements	Missing Compliance Elements	Status
MOD-013-0	RRO Dynamics Data Requirements and Reporting Procedures			Replaced by MOD-013-1
MOD-013-1	Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedure			Pending revision, filed September 2006
MOD-014-0	Development of Interconnection-Specific Steady State System Models			Pending, filed April 2006
MOD-015-0	Development of Interconnection-Specific Dynamics System Models			Pending, filed April 2006
MOD-016-0	Actual and Forecast Demands, Net Energy for Load, Controllable DSM			Replaced by MOD-016-1
MOD-016-1	Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management			Pending revision, filed September 2006
MOD-017-0	Aggregated Actual and Forecast Demands and Net Energy for Load	R1		Pending, filed April 2006
MOD-018-0	Reports of Actual and Forecast Demand Data			Pending, filed April 2006
MOD-019-0	Forecasts of Interruptible Demands and DCLM Data	R1		Pending, filed April 2006
MOD-020-0	Providing Interruptible Demands and DCLM Data			Pending, filed April 2006
MOD-021-0	Accounting Methodology for Effects of Controllable DSM in Forecasts			Pending, filed April 2006
MOD-024-1	Verification of Generator Gross and Net Real Power Capability	R3		Pending, filed April 2006
MOD-025-1	Verification of Reactive Power Capability	R3		Pending, filed April 2006
PER-001-0	Operating Personnel Responsibility and Authority			Pending, filed April 2006
PER-002-0	Operating Personnel Training	R3.1		Pending, filed April 2006
PER-003-0	Operating Personnel Credentials			Pending, filed April 2006
PER-004-0	Reliability Coordination – Staffing		Yes	Pending, filed April 2006
PRC-001-0	System Protection Coordination		Yes	Pending, filed April 2006
PRC-002-0	Define and Document Disturbance			Replaced by

Number	Title	Fill-in-the Blank Requirements	Missing Compliance Elements	Status
	Monitoring Equipment Requirements			PRC-002-1
PRC-002-1	Define Regional Disturbance Monitoring and Reporting Requirements			Pending revision, filed September 2006
PRC-003-1	Regional Requirements for Transmission and Generation Protection System Misoperations			Pending, filed April 2006
PRC-004-1	Analysis and Mitigation of Transmission and Generation Protection System Misoperations	R1, R2, R3		Pending, filed April 2006
PRC-005-1	Transmission and Generation Protection System Maintenance and Testing			Pending, filed April 2006
PRC-006-0	Development and Documentation of Regional UFLS Programs			Pending, filed April 2006
PRC-007-0	Assuring Consistency with Regional UFLS Programs	R1		Pending, filed April 2006
PRC-008-0	Underfrequency Load Shedding Equipment Maintenance Programs	R1, R2		Pending, filed April 2006
PRC-009-0	UFLS Performance Following an Underfrequency Event	R1		Pending, filed April 2006
PRC-010-0	Assessment of the Design and Effectiveness of UVLS Program			Pending, filed April 2006
PRC-011-0	UVLS System Maintenance and Testing			Pending, filed April 2006
PRC-012-0	Special Protection System Review Procedure			Pending, filed April 2006
PRC-013-0	Special Protection System Database			Pending, filed April 2006
PRC-014-0	Special Protection System Assessment			Pending, filed April 2006
PRC-015-0	Special Protection System Data and Documentation	R1, R2, R3		Pending, filed April 2006
PRC-016-0	Special Protection System Misoperations	R1		Pending, filed April 2006
PRC-017-0	Special Protection System Maintenance and Testing			Pending, filed April 2006
PRC-018-1	Disturbance Monitoring Equipment Installation and Data Reporting	R1, R2, R3, R4, R5, R6		Pending, new filed September 2006
PRC-020-1	Under-Voltage Load Shedding			Pending, filed

Number	Title	Fill-in-the Blank Requirements	Missing Compliance Elements	Status
	Program Database			April 2006
PRC-021-1	Under-Voltage Load Shedding Program Data			Pending, filed April 2006
PRC-022-1	Under-Voltage Load Shedding Program Performance			Pending, filed April 2006
TOP-001-0	Reliability Responsibilities and Authorities		Yes	Pending, filed April 2006
TOP-002-0	Normal Operations Planning	R6, R12	Yes	Replaced by TOP-002-1
TOP-002-1	Normal Operations Planning	R6, R12	Yes	Pending revision, filed September 2006
TOP-003-0	Planned Outage Coordination			Pending, filed April 2006
TOP-004-0	Transmission Operations	R3	Yes	Pending, filed April 2006
TOP-005-1	Operational Reliability Information			Pending, filed April 2006
TOP-006-0	Monitoring System Conditions		Yes	Pending, filed April 2006
TOP-007-0	Reporting SOL and IROL Violations			Pending, filed April 2006
TOP-008-0	Response to Transmission Limit Violations		Yes	Pending, filed April 2006
TPL-001-0	System Performance Under Normal Conditions			Pending, filed April 2006
TPL-002-0	System Performance Following Loss of a Single Bulk Electric System Element			Pending, filed April 2006
TPL-003-0	System Performance Following Loss of Two or More Bulk Electric System Elements			Pending, filed April 2006
TPL-004-0	System Performance Following Extreme Bulk Electric System Events			Pending, filed April 2006
TPL-005-0	Regional and Interregional Self-Assessment Reliability Reports			Pending, filed April 2006
TPL-006-0	Assessment Data from Regional Reliability Organizations			Pending, filed April 2006
VAR-001-0	Voltage and Reactive Control		Yes	Replaced by VAR-001-1
VAR-001-1	Voltage and Reactive Control			Pending

Number	Title	Fill-in-the Blank Requirements	Missing Compliance Elements	Status
				revision, filed September 2006
VAR-002-1	Generator Operation for Maintaining Network Voltage Schedules			Pending, new filed August 2006

Note the Glossary of Terms Used in Reliability Standards has been updated to include new terms approved by the NERC board within the new and revised standards. Standards FAC-004-0 and FAC-005-0 were filed on April 4, 2006, but have been superseded by FAC-008-1 and FAC-009-1 respectively. NERC hereby withdraws its Notice of Filing of FAC-004-0 and FAC-005-0.

Justification for Proposed Reliability Standards

This section summarizes the development of the proposed reliability standards and provides justification of the proposed standards. This section describes the reliability objectives to be achieved by approving the standards, the stakeholder ballot results, and how any major objections were addressed.

Supporting details are available in **Exhibit C**, which is the complete development record for the proposed reliability standards. **Exhibit C** contains copies of successive drafts of the standards; the implementation plan; the ballot pool and final ballot results by entity name; all public comments received during the development of the standard; discussions of those public comments; and descriptions of how those comments were considered in developing the standards. The standard drafting team rosters are provided in **Exhibit D**.

Cyber Security Standards (CIP-002-1 to CIP-009-1)

These eight new standards provide a comprehensive set of requirements to protect the bulk power system from malicious cyber attacks. Because there are unique aspects of cyber protection for each entity and its assets, the standards require bulk power system owners, operators, and users to step through a sequence of establishing a risk-based vulnerability assessment method and using that method to identify and prioritize critical assets and critical cyber assets. Once the critical cyber assets are identified, the standards require the responsible entities to establish plans, protocols, and controls to safeguard physical and electronic access, to train personnel on security matters, to report security incidents, and to be prepared for recovery actions. The proposed cyber security standards propose the most comprehensive set of requirements ever utilized on a widespread basis in the electric industry.

Because of the expanded scope of facilities and entities covered by these standards, and the investment in security upgrades required in many cases, the implementation plan calls for a three-year phase-in to achieve full compliance with all requirements. The transition builds progressively from the requirements that were previously in place with the 1200 Urgent Action Standard that was replaced. In other words, the industry is progressively improving in security measures in stages from the level established in 2003 with the interim standard to an extraordinarily robust set of auditable requirements by end of year 2009.

The proposed cyber security standards fulfill Recommendations 32 and 32.A of the United States/Canada Power System Outage Task Force ("Task Force") report. These recommendations state, in part, that NERC should finalize and implement the CIP-002-1 to CIP-009-1 standards, that NERC standards related to physical and cyber security should be made mandatory and enforceable, and that NERC should take actions to better communicate and enforce these standards. To help the industry embrace and implement these standards, NERC has initiated a series of ten industry workshops that will be presented across North America by year end.

These proposed new standards are much more rigorous and precise compared to the urgent action cyber security standard. The standards provide clear requirements with expected measurable outcomes. Compliance information is provided to allow rigorous monitoring and audits of the standards. NERC believes the new standards address the concerns expressed in the Staff Report that were directed toward the interim, urgent action cyber security standard.

Stakeholders approved the cyber security standards by a weighted average 88.8%, with a voter participation of 91.9%. Initial balloting was conducted in the period February 17–27, 2006. Because there were negative votes with comments on the initial ballot, a recirculation ballot was conducted in the period March 14–24. Of 294 total votes cast, 13 entities changed a negative vote to an affirmative vote in the recirculation ballot; and one entity changed an affirmative to a negative.

The drafting team successfully resolved the vast majority of issues raised in the development of these standards. In the end, there were several unresolved minority objections with which the drafting team and the majority of stakeholders disagreed:

- Some requirements are too costly to implement and may have little return on investment.
- The scope of requirements should be limited to critical cyber assets within bulk power system control centers.
- Levels of non-compliance are too high for some requirements that seem to be primarily administrative.
- The definition of critical asset leaves room for ambiguity in interpretation.

The Standard Authorization Request (SAR) for the cyber security standards was submitted on May 2, 2003. The SAR was posted twice for public comment to achieve consensus on the scope and justification for the standards. The Standards Authorization Committee (SAC) appointed a drafting team of security experts to begin development of the standard in May 2004. The drafting team posted three drafts of the standards for public comment in September 2004, January 2005, and May 2005. Four factors contributed to the extended development time for these standards: 1) the extraordinary complexity of the new cyber security standards; 2) the expanded reach of the standards to include additional entities and facilities not previously covered by the interim cyber security standard; 3) reassignment of resources to investigate the August 2003 blackout; and 4) reassignment of resources to develop the Version 0 standards.

Coordinate Interchange (INT-001-1 and INT-003-1 to INT-010-1)

These standards expand and clarify the reliability requirements for energy interchange transactions, allowing the transfer of energy across the bulk power system in a controlled and reliable manner.

Stakeholders approved the coordinate interchange standards by a weighted average 77.9%, with a voter participation of 92.9%. Initial balloting was conducted in the period February 17–27, 2006. Because there were negative votes with comments on the initial ballot, a recirculation ballot was conducted in the period March 14–24. Of the 210 votes received, two entities changed from a 'negative' vote to an 'affirmative' vote in the recirculation ballot.

There were two significant unresolved minority objections to the proposed standards that caused the approval percentage to be less than historical levels typically seen with other standards. The dissenters were primarily from the Northeast Power Coordinating Council (NPCC) and the Florida Reliability Coordinating Council (FRCC):

- Eighteen of the 40 negative ballots were from NPCC. These entities incorrectly interpreted the requirement that the transmission service provider must analyze an interchange request to determine if it will violate prevailing limits as meaning the transmission service provider must perform a 'wide area' reliability assessment, and indicated that this is not an appropriate function of a transmission service provider.
- Fifteen of the 40 negative ballots were from FRCC. These entities objected to the deletion of a Version 0 requirement to tag interchange transactions internal to a balancing area. This information is provided in tags today, but is not used by the IDC. FRCC members indicate this information may be useful to FRCC in the

future. Several FRCC members also questioned the need to assign requirements to the interchange authority, because transaction scheduling continues today to be conducted only between balancing authority areas.

Most of the remaining negative votes were related to a lack of measures in Version 0 standards INT-001 to INT-004. This was an apparent point of confusion for these voters, as the missing compliance information for these standards is being developed through a separate project for approval later in 2006. INT-001-1 and INT-003-1 are undergoing further revision as part of the project to develop missing compliance elements and will be updated in the November 2006 filing. INT-002-0 is being retired and INT-004-1 has compliance information.

The Standard Authorization Request (SAR) for the coordinate interchange standards was submitted as one of the 11 original SARs created when the new standards process was launched in 2002. The SAR was posted three times for public comment in April 2002, August 2002 and January 2003. The drafting team prepared the first draft of the standards for public comment in December 2003. During this time, work was intentionally delayed to redirect resources to the development of the Version 0 standards and to resolve how the interchange authority and balancing authority should be applied in NERC's standards. With the Version 0 standards completed and the changes in use of the functional model incorporated, the drafting team published a second draft of the standards for public comment in September 2005. The final draft was posted for pre-ballot review in January 2006.

System Restoration Plans (EOP-005-1)

This standard ensures that plans, procedures, and resources are available to restore the electric system to a normal condition in the event of a partial or total shut down of the system. Specifically, this standard requires the transmission operator, balancing authority, and reliability coordinator to have effective restoration plans, test those plans, and be able to restore the interconnection following a blackout. This standard also requires operating personnel to be trained in these plans. New requirements are added compared to the Version 0 standard to address the need to verify or test blackstart capability that is needed to support the restoration plans and to verify that system operators have initial switching instructions to start a restoration from blackstart units. The revised standard proposes to add measures on testing of blackstart capability, determination of the appropriate location of blackstart capability, and validation of cranking paths to restart the system.

Stakeholders approved this standard by a weighted average 96.6%, with a voter participation of 83.4%. The initial ballot was conducted March 21–30, 2006. Because there were negative votes with comments on the initial ballot, a recirculation ballot was conducted in the period April 17–26.

There were several unresolved minority objections to the proposed standard. The drafting team was unable to address these objections because they were outside the work scope of the SAR, which was limited to translating the previously existing Phase III-IV planning standards. The objections will be addressed in a future revision of the standard:

- The training requirements need further clarification.
- The requirement to coordinate the restoration plan with generators does not distinguish whether the requirement extends to all generators or those necessary for system black start.
- It is not clear how an independent transmission company would meet the requirement for coordination with generation.

The SAR to translate the Phase III-IV planning standards was introduced in November 2004. Draft 1 of the standard was posted for public comment from April to June 2005. Draft 2 was posted for public comment from October to November 2005. The final draft was posted for a 30-day pre-ballot review beginning February 17, 2006.

Dynamics Data Requirements and Reporting Procedures (MOD-013-1)

This standard ensures that transmission owners, transmission planners, generator owners, and resource planners within each interconnection are using consistent data specifications, information exchange, and modeling techniques to simulate the dynamic behavior of the bulk power system. System models enable planners to simulate how a portion (or even all) of the interconnection will react to various disturbances — specifically, whether these disturbances result in the bulk power system stabilizing at a new point of equilibrium, or becoming unstable. New requirements added compared to the Version 0 standard address the need to provide design data for new or refurbished excitation systems prior to the installation date.

The revisions in MOD-013-1 address aspects of Task Force Recommendation 24 regarding improvements in the quality of modeling the dynamic behavior of generator controls and excitation systems and other dynamic devices in the power system. The need to improve and standardize dynamic models was a key lesson from the effort to construct post-event simulations of the August 14, 2003 Northeast blackout.

Stakeholders approved this standard by a weighted average 88.6%, with a voter participation of 83.1%. An initial ballot was conducted March 21–30, 2006. Because there were negative votes with comments on the initial ballot, a recirculation ballot was conducted in the period April 17–26.

There were several unresolved minority objections to the proposed standard. The drafting team was unable to address these objections because they were outside the work scope of the SAR, which was limited to translating the previously existing Phase III-IV planning standards. The objections will be addressed in a future revision of the standard:

- Methods for determining equipment dynamic data are not sufficiently available in common practice.
- Dynamic data should be based on post-commissioning equipment tests, not estimated or typical values.
- The implementation of the standard should be delayed to allow more time for facility testing.
- Levels of noncompliance need to be adjusted.

With regard to the second item above, the drafting team notes that the reference to estimated or typical data refers only to the period before commissioning of a facility, and that a separate requirement in the standard refers to the need to provide actual data after commissioning of the facility.

The SAR to translate the Phase III-IV planning standards was introduced in November 2004. Draft 1 of the standard was posted for public comment from April to June 2005. Draft 2 was posted for public comment from October to November 2005. The final draft was posted for a 30-day pre-ballot review beginning February 17, 2006.

Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management Standard (MOD-016-1)

This standard ensures actual demand data are available to assess reliability performance and validate past events and system modeling databases. Forecast demand data and controllable demand data are needed to assess future reliability performance and identify the need for system reinforcements. A new requirement is added to ensure that customer demand is counted once and only once in developing actual and forecast customer demand values. This standard is part of the overall effort to improve system modeling noted in Task Force Recommendation 24.

Stakeholders approved this standard by a weighted average 99.8%, with a voter participation of 83.2%. An initial ballot was conducted March 21–30, 2006. Because there was one negative vote with a comment on the initial ballot, a recirculation ballot was conducted in the period April 17–26. There were no major unresolved minority views with the approval of this standard.

The SAR to translate the Phase III-IV planning standards was introduced in November 2004. Draft 1 of the standard was posted for public comment from April to June 2005. Draft 2 was posted for public comment from October to November 2005. The final draft was posted for a 30-day pre-ballot review beginning February 17, 2006.

Protection and Control Standards (PRC-002-1 and PRC-018-1)

PRC-002-1 and PRC-018-1 are a subset of the Phase III & IV planning standards that the board directed the Planning Committee to propose as a follow-on effort to the Version 0 standards.

PRC-002-1 requires regional reliability organizations to establish requirements for installation of disturbance monitoring equipment and reporting of disturbance data to facilitate the analysis of events and verify system models. The drafting team made major revisions based in large part, on lessons learned from the blackout. The requirements in Version 1 are substantially more detailed and specific compared to the Version 0 standard. Most importantly, a new requirement was added regarding where disturbance monitoring equipment must be installed within the system. Additional specificity was provided in the requirements for event recording, fault recording, and dynamic disturbance recording.

PRC-018-1 requires transmission and generation owners to install disturbance monitoring equipment and to report the disturbance data in accordance with the regional requirement to facilitate the analyses of events. As a critical response to Task Force recommendations, this is the first NERC standard that specifically requires entities to install equipment to protect the reliability of the bulk power system.

Requirements for time synchronization of disturbance monitoring devices and retention of disturbance data are now made uniform in the proposed revisions, rather than leaving that determination to the regional reliability organizations. The requirement to synchronize disturbance recorders to within 2 milliseconds of a precise time standard is an example of a key lesson from Task Force Recommendation 28 now captured in PRC-018-1. Several requirements were moved out of PRC-002 into PRC-018 to provide a uniform set of metrics that will be applied to all facility owners, without regional variation.

PRC-002 and PRC-018 are closely related and were balloted with a single ballot. In the initial ballot conducted June 15–26, 2006, stakeholders approved PRC-002-1 and PRC-018-1 by a weighted average 94.1%, with a voter participation of 85.3 %. Because there were negative votes with comments on the initial ballot, a recirculation ballot was conducted in the period July 6–15, 2006. The final vote was 92.5% affirmative, with 91.0% of the ballot pool voting.

The drafting team did not make any changes to PRC-002-1 and PRC-018-1 as a result of the negative comments. Most comments suggested modifications that are outside the scope of work assigned to the drafting team.

The SAR for PRC-002-1 and PRC-018-1 was posted for public comment from December 2, 2004 through January 7, 2005. Draft 1 of the standards was posted for public comment from April 21 through June 13, 2005. Draft 2 of the standards was posted for public comment from September 1 through October 15, 2005. Draft 3 of the standards was posted for public comment from December 1, 2005 through January 17, 2006. Draft 4 of the standards was posted for public comment from April 3 through May 3, 2006. The final draft of the standards was posted for pre-ballot review from May 15 through June 13, 2006.

Some requirements of PRC-018-1 still have regional fill-in-the-blank aspects. The plan to address this aspect of the standard is being addressed through the development of a work plan that will be filed in November addressing all of the fill-in-the-blank standards.

Voltage and Reactive Control Standards (VAR-001-1, VAR-002-1, and TOP-002-1)

VAR-001-1 and VAR-002-1 are a subset of the Phase III & IV planning standards that the board directed the Planning Committee to propose as a follow-on effort to the Version 0 standards. New requirements were added to VAR-001-1 for transmission operators to maintain transmission system voltage or reactive power within schedules and limits. VAR-002-1, which is a new standard, requires generator owners and operators to maintain and operate generators to meet voltage and reactive power schedules and to provide automatic voltage controls necessary for bulk power system reliability. The revisions in VAR-001-1, and particularly the new VAR-002-1 standard, address Task Force Recommendation 23.1 to strengthen reactive power and voltage control practices. These standards contain more precise measures and more complete compliance information, and expand the scope to include generators. TOP-002-1 was revised to be consistent with shifting the generator requirements into VAR-002-1.

An initial ballot of these standards was conducted from June 15 to 26. The standards were approved by a weighted average 91.1% and a quorum of 82.6%. Because there were several negative votes with comments, a re-circulation ballot was conducted from July 6 to July 15. In the final vote tally, the approval had increased slightly to 92.1% with a quorum of 89.8%.

Some commenters suggested improvements that were outside the scope of the Phase III-IV project assignment to translate the prior planning standards. There were no other major unresolved issues.

The SAR for VAR-001 and VAR-002 was posted for public comment from December 2, 2004 through January 7, 2005. Draft 1 of the standards was posted for public comment from April 21 through June 13, 2005. Draft 2 of the standards was posted for public comment from October 15 through November 30, 2005. Draft 3 of the standards was posted for public comment from March 1 through April 15, 2006. The final draft of the standards was posted for pre-ballot review from May 15 through June 13, 2006.

Transmission Loading Relief Standard (IRO-006-3)

This standard requires the reliability coordinator to 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 Transmission Loading Relief (TLR) process is achieved.

There are two separate sets of changes associated with IRO-006 — the first standard set of changes (Version 2) modifies the steps in the TLR procedure following a level 3b curtailment. This change provides for the reallocation of markets flows and interchange transactions at the top of the next hour following the issuance of a TLR level 3b curtailment of transmission service. The reliability benefit is that a reliability coordinator will no longer be required to call a TLR level 3a as soon as the System Operating Limit or Interconnection Reliability Operating Limit violation that caused the TLR Level 3b to be initiated has been mitigated, since the revision to the procedure results automatically in a next hour reallocation of transactions and market redispatch.

The initial ballot for IRO-006-2 was conducted May 22–31, 2006 but failed to reach the required quorum of 75%. IRO-006-2 was re-balloted from June 5–23, 2006 and was approved by a weighted average of 99.7% with voter participation of 87.4%. Because there were no negative votes with comments on the initial ballot, there was no re-circulation ballot.

There were only two comments submitted with the ballot for IRO-006-2. Both comments were submitted with affirmative ballots. There was one negative ballot submitted, but it was not accompanied by a comment.

The SAR and standard for IRO-006-2 were posted for public comment from February 17 through April 3, 2006. Minor revisions not altering the technical content were made and IRO-006-2 was posted for pre-ballot review from April 17 through May 16, 2006.

The second set of changes associated with IRO-006 is to add a variance for SPP (IRO-006-3). The variance will allow SPP to supply market flow values to the Interchange Distribution Calculator that represent impacts on flowgates due to energy dispatched by SPP that is not tagged as a bilateral transaction. This is an extension of an existing variance that is in place within the NERC standards (IRO-006-1) for MISO and PJM.

The initial ballot for IRO-006-3 was conducted April 4 – 13, 2006 but failed to reach the required quorum of 75%. A re-ballot was conducted April 28 – May 13, 2006 and it failed to reach the required quorum of 75%. In accordance with the standards process, the original ballot pool was dissolved and a new ballot pool was formed.

The new initial ballot was conducted June 27–July 14, 2006. The results of the initial ballot were 85.7% approval with 78.8% of the ballot pool voting. Thus, a quorum was achieved with the reconstituted ballot pool. A re-circulation ballot was conducted July 21-30 with the final results being an affirmative vote of 87.4%, with 82.5% of the ballot pool voting.

The SAR was posted for comment from October 6 through November 7, 2005. The first draft of the standard was posted for comment from February 17 through March 20, 2006 and included text that would have modified the IDC so that it would accept a broad array of market information, which would have removed the need for any variances, including the SPP variance. Comments on the first draft of the standard indicated that the standard needed to undergo significant changes before it could be approved.

The requester determined that the changes to the standard could not be accomplished in time to begin SPP's market operation on May 1, 2006. The requester asked that the standard be treated as an urgent action and the SAC approved this change. The urgent action standard was posted for pre-ballot review from March 1 through March 30, 2006 and included the changes specific to the SPP variance, but did not include the more generic changes to the IDC.

Some commenters suggested that the requester should not have been allowed to use the urgent action process because the modification to the standard was not needed to support reliability. There are no other major unresolved issues.

Urgent Action SPP Variance on Inadvertent Interchange (BAL-006-1)

This modification to BAL-006 extends an existing approved variance applied for MISO to also apply in the new market to be operated by the Southwest Power Pool. The difference is necessary in a regional market encompassing multiple balancing areas, in which the market operator can manage inadvertent interchange on behalf of its member balancing areas without adverse impact on the interconnection and without requiring tagging of transactions between the member balancing areas.

In the initial balloting conducted in the period March 21–30, 2006, stakeholders approved BAL-006-1 by a weighted average 94.2%, with a voter participation of 78.6%. Because there were negative votes with comments on the initial ballot, a recirculation ballot was conducted in the period April 17–26. The final vote was 95.8% affirmative, with 82.3% of the ballot pool voting.

Most of the entities casting negative votes indicated that the SPP variance did not qualify as an urgent action and should have followed the regular standards process for approval. Several noted a need to explicitly state the standard will expire in one year, which is the case. The start date for the SPP market changed from May 2006, to November 2006, after the urgent action process was initiated and the urgent action approval was allowed to continue to completion.

The urgent action revision to BAL-006 was posted for a 30-day pre-ballot review beginning February 17, 2006. Without further action the urgent action component of the standard (the SPP variation) will expire on August 2, 2007. The variance must be made a permanent part of the standard or be separately renewed before then, or else it will expire.

Respectfully submitted,

NORTH AMERICAN ELECTRIC
RELIABILITY COUNCIL

By ___/s/ Rick Sergel_____
President and Chief Executive Officer
North American Electric Reliability Council
116-390 Village Boulevard
Princeton, New Jersey 08540-5731

September 11, 2006

Exhibit A — Proposed Reliability Standards

A. Introduction

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

2. **Number:** BAL-006-1

3. **Purpose:**

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

4. **Applicability:**

   4.1. Balancing Authorities.

5. **Effective Date:** May 1, 2006
   This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.

B. Requirements

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

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

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

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

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

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

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

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

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

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

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

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

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

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

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

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

2. Levels of Non Compliance

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

E. Regional Differences

1. MISO RTO Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004. This regional difference will be extended to include SPP effective May 1, 2006.

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	April 6, 2006	Added following to "Effective Date:" This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata

A. Introduction

1. **Title:** Cyber Security — Critical Cyber Asset Identification

2. **Number:** CIP-002-1

3. **Purpose:** NERC Standards CIP-002 through CIP-009 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

   These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed. Responsible Entities should interpret and apply Standards CIP-002 through CIP-009 using reasonable business judgment.

   Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

   Standard CIP-002 requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. **Applicability:**

   4.1. Within the text of Standard CIP-002, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Reliability Organizations.

   4.2. The following are exempt from Standard CIP-002:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** June 1, 2006

B. Requirements

The Responsible Entity shall comply with the following requirements of Standard CIP-002:

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.1. The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.1. Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.

R1.2.2. Transmission substations that support the reliable operation of the Bulk Electric System.

R1.2.3. Generation resources that support the reliable operation of the Bulk Electric System.

R1.2.4. Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

R1.2.6. Special Protection Systems that support the reliable operation of the Bulk Electric System.

R1.2.7. Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.

R2. Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.

R3. Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

R4. Annual Approval — A senior manager or delegate(s) shall approve annually the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

C. Measures

The following measures will be used to demonstrate compliance with the requirements of Standard CIP-002:

M1. The risk-based assessment methodology documentation as specified in Requirement R1.

M2. The list of Critical Assets as specified in Requirement R2.

M3. The list of Critical Cyber Assets as specified in Requirement R3.

M4. The records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.1.1 Regional Reliability Organizations for Responsible Entities.

1.1.2 NERC for Regional Reliability Organization.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

1.3.1 The Responsible Entity shall keep documentation required by Standard CIP-002 from the previous full calendar year

1.3.2 The compliance monitor shall keep audit records for three calendar years.

1.4. Additional Compliance Information

1.4.1 Responsible Entities shall demonstrate compliance through self-certification or audit, as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1 Level 1: The risk assessment has not been performed annually.

2.2 Level 2: The list of Critical Assets or Critical Cyber Assets exist, but has not been approved or reviewed in the last calendar year.

2.3 Level 3: The list of Critical Assets or Critical Cyber Assets does not exist.

2.4 Level 4: The lists of Critical Assets and Critical Cyber Assets do not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	R3.2 — Change “Control Center” to “control center”	03/24/06

A. Introduction

1. **Title:** Cyber Security — Security Management Controls

2. **Number:** CIP-003-1

3. **Purpose:** Standard CIP-003 requires that Responsible Entities have minimum security management controls in place to protect Critical Cyber Assets. Standard CIP-003 should be read as part of a group of standards numbered Standards CIP-002 through CIP-009. Responsible Entities should interpret and apply Standards CIP-002 through CIP-009 using reasonable business judgment.

4. **Applicability:**

   4.1. Within the text of Standard CIP-003, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Reliability Organizations.

   4.2. The following are exempt from Standard CIP-003:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002, identify that they have no Critical Cyber Assets.

5. **Effective Date:** June 1, 2006

B. Requirements

The Responsible Entity shall comply with the following requirements of Standard CIP-003:

R1. Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:

R1.1. The cyber security policy addresses the requirements in Standards CIP-002 through CIP-009, including provision for emergency situations.

R1.2. The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.

R1.3. Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.

R2. Leadership — The Responsible Entity shall assign a senior manager with overall responsibility for leading and managing the entity's implementation of, and adherence to, Standards CIP-002 through CIP-009.

R2.1. The senior manager shall be identified by name, title, business phone, business address, and date of designation.

R2.2. Changes to the senior manager must be documented within thirty calendar days of the effective date.

R2.3. The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.

R3. Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).

R3.1. Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).

R3.2. Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures, or a statement accepting risk.

R3.3. Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.

R4. Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.

R4.1. The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.

R4.2. The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.

R4.3. The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.

R5. Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.

R5.1. The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.

R5.1.1. Personnel shall be identified by name, title, business phone and the information for which they are responsible for authorizing access.

R5.1.2. The list of personnel responsible for authorizing access to protected information shall be verified at least annually.

R5.2. The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.

R5.3. The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.

R6. Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.

C. Measures

The following measures will be used to demonstrate compliance with the requirements of Standard CIP-003:

M1. Documentation of the Responsible Entity's cyber security policy as specified in Requirement R1. Additionally, the Responsible Entity shall demonstrate that the cyber security policy is available as specified in Requirement R1.2.

M2. Documentation of the assignment of, and changes to, the Responsible Entity's leadership as specified in Requirement R2.

M3. Documentation of the Responsible Entity's exceptions, as specified in Requirement R3.

M4. Documentation of the Responsible Entity's information protection program as specified in Requirement R4.

M5. The access control documentation as specified in Requirement R5.

M6. The Responsible Entity's change control and configuration management documentation as specified in Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.1.1 Regional Reliability Organizations for Responsible Entities.

1.1.2 NERC for Regional Reliability Organization.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

1.3.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year.

1.3.2 The compliance monitor shall keep audit records for three years.

1.4. Additional Compliance Information

1.4.1 Responsible Entities shall demonstrate compliance through self-certification or audit, as determined by the Compliance Monitor.

1.4.2 Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and approved by the designated senior manager or delegate(s). Refer to CIP-003, Requirement R3. Duly authorized exceptions will not result in non-compliance.

2. Levels of Noncompliance

2.1. Level 1:

2.1.1 Changes to the designation of senior manager were not documented in accordance with Requirement R2.2; or,

2.1.2 Exceptions from the cyber security policy have not been documented within thirty calendar days of the approval of the exception; or,

2.1.3 An information protection program to identify and classify information and the processes to protect information associated with Critical Cyber Assets has not been assessed in the previous full calendar year.

2.2. Level 2:

2.2.1 A cyber security policy exists, but has not been reviewed within the previous full calendar year; or,

2.2.2 Exceptions to policy are not documented or authorized by the senior manager or delegate(s); or,

2.2.3 Access privileges to the information related to Critical Cyber Assets have not been reviewed within the previous full calendar year; or,

2.2.4 The list of designated personnel responsible to authorize access to the information related to Critical Cyber Assets has not been reviewed within the previous full calendar year.

2.3. Level 3:

2.3.1 A senior manager has not been identified in accordance with Requirement R2.1; or,

2.3.2 The list of designated personnel responsible to authorize logical or physical access to protected information associated with Critical Cyber Assets does not exist; or,

2.3.3 No changes to hardware and software components of Critical Cyber Assets have been documented in accordance with Requirement R6.

2.4. Level 4:

2.4.1 No cyber security policy exists; or,

2.4.2 No identification and classification program for protecting information associated with Critical Cyber Assets exists; or,

2.4.3 No documented change control and configuration management process exists.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** Cyber Security — Personnel & Training
2. **Number:** CIP-004-1
3. **Purpose:** Standard CIP-004 requires that personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including contractors and service vendors, have an appropriate level of personnel risk assessment, training, and security awareness. Standard CIP-004 should be read as part of a group of standards numbered Standards CIP-002 through CIP-009. Responsible Entities should interpret and apply Standards CIP-002 through CIP-009 using reasonable business judgment.
4. **Applicability:**

4.1. Within the text of Standard CIP-004, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Interchange Authority.

4.1.4 Transmission Service Provider.

4.1.5 Transmission Owner.

4.1.6 Transmission Operator.

4.1.7 Generator Owner.

4.1.8 Generator Operator.

4.1.9 Load Serving Entity.

4.1.10 NERC.

4.1.11 Regional Reliability Organizations.

4.2. The following are exempt from Standard CIP-004:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002, identify that they have no Critical Cyber Assets.

5. **Effective Date:** June 1, 2006

B. Requirements

The Responsible Entity shall comply with the following requirements of Standard CIP-004:

R1. Awareness — The Responsible Entity shall establish, maintain, and document a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as:

- Direct communications (e.g., emails, memos, computer based training, etc.);
- Indirect communications (e.g., posters, intranet, brochures, etc.);
- Management support and reinforcement (e.g., presentations, meetings, etc.).

R2. Training — The Responsible Entity shall establish, maintain, and document an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and review the program annually and update as necessary.

R2.1. This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained within ninety calendar days of such authorization.

R2.2. Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:

R2.2.1. The proper use of Critical Cyber Assets;

R2.2.2. Physical and electronic access controls to Critical Cyber Assets;

R2.2.3. The proper handling of Critical Cyber Asset information; and,

R2.2.4. Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.

R2.3. The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.

R3. Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access. A personnel risk assessment shall be conducted pursuant to that program within thirty days of such personnel being granted such access. Such program shall at a minimum include:

R3.1. The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven-year criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing collective bargaining unit agreements, depending upon the criticality of the position.

R3.2. The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.

R3.3. The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004.

R4. Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.

R4.1. The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.

R4.2. The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.

C. Measures

The following measures will be used to demonstrate compliance with the requirements of Standard CIP-004:

M1. Documentation of the Responsible Entity's security awareness and reinforcement program as specified in Requirement R1.

M2. Documentation of the Responsible Entity's cyber security training program, review, and records as specified in Requirement R2.

M3. Documentation of the personnel risk assessment program and that personnel risk assessments have been applied to all personnel who have authorized cyber or authorized unescorted physical access to Critical Cyber Assets, as specified in Requirement R3.

M4. Documentation of the list(s), list review and update, and access revocation as needed as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.1.1 Regional Reliability Organizations for Responsible Entities.

1.1.2 NERC for Regional Reliability Organization.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

1.3.1 The Responsible Entity shall keep personnel risk assessment documents in accordance with federal, state, provincial, and local laws.

1.3.2 The Responsible Entity shall keep all other documentation required by Standard CIP-004 from the previous full calendar year.

1.3.3 The compliance monitor shall keep audit records for three calendar years.

1.4. Additional Compliance Information

1.4.1 Responsible Entities shall demonstrate compliance through self-certification or audit, as determined by the Compliance Monitor.

1.4.2 Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and approved by the designated senior manager or delegate(s). Duly authorized exceptions will not result in non-compliance. Refer to CIP-003 Requirement R3.

2. Levels of Noncompliance

2.1. Level 1:

2.1.1 Awareness program exists, but is not conducted within the minimum required period of quarterly reinforcement; or,

2.1.2 Training program exists, but records of training either do not exist or reveal that personnel who have access to Critical Cyber Assets were not trained as required; or,

2.1.3 Personnel risk assessment program exists, but documentation of that program does not exist; or,

2.1.4 List(s) of personnel with their access rights is available, but has not been reviewed and updated as required.

2.1.5 One personnel risk assessment is not updated at least every seven years, or for cause; or,

2.1.6 One instance of personnel (employee, contractor or service provider) change other than for cause in which access to Critical Cyber Assets was no longer needed was not revoked within seven calendar days.

2.2. Level 2:

2.2.1 Awareness program does not exist or is not implemented; or,

2.2.2 Training program exists, but does not address the requirements identified in Standard CIP-004; or,

2.2.3 Personnel risk assessment program exists, but assessments are not conducted as required; or,

2.2.4 One instance of personnel termination for cause (employee, contractor or service provider) in which access to Critical Cyber Assets was not revoked within 24 hours.

2.3. Level 3:

2.3.1 Training program exists, but has not been reviewed and updated at least annually; or,

2.3.2 A personnel risk assessment program exists, but records reveal program does not meet the requirements of Standard CIP-004; or,

2.3.3 List(s) of personnel with their access control rights exists, but does not include service vendors and contractors.

2.4. Level 4:

2.4.1 No documented training program exists; or,

2.4.2 No documented personnel risk assessment program exists; or,

2.4.3 No required documentation created pursuant to the training or personnel risk assessment programs exists.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	D.2.2.4 — Insert the phrase “for cause” as intended. “One instance of personnel termination for cause…”	03/24/06
1	06/01/06	D.2.1.4 — Change “access control rights” to “access rights.”	06/05/06

A. Introduction

1. **Title:** Cyber Security — Electronic Security Perimeter(s)

2. **Number:** CIP-005-1

3. **Purpose:** Standard CIP-005 requires the identification and protection of the Electronic Security Perimeter(s) inside which all Critical Cyber Assets reside, as well as all access points on the perimeter. Standard CIP-005 should be read as part of a group of standards numbered Standards CIP-002 through CIP-009. Responsible Entities should interpret and apply Standards CIP-002 through CIP-009 using reasonable business judgment.

4. **Applicability**

   4.1. Within the text of Standard CIP-005, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Reliability Organizations.

   4.2. The following are exempt from Standard CIP-005:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002, identify that they have no Critical Cyber Assets.

5. **Effective Date:** June 1, 2006

B. Requirements

The Responsible Entity shall comply with the following requirements of Standard CIP-005:

R1. Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).

R1.1. Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).

R1.2. For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.

R1.3. Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).

R1.4. Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005.

R1.5. Cyber Assets used in the access control and monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Requirements R1 and R3 through R9, Standard CIP-008, and Standard CIP-009.

R1.6. The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.

R2. Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).

R2.1. These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.

R2.2. At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.

R2.3. The Responsible Entity shall maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).

R2.4. Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.

R2.5. The required documentation shall, at least, identify and describe:

R2.5.1. The processes for access request and authorization.

R2.5.2. The authentication methods.

R2.5.3. The review process for authorization rights, in accordance with Standard CIP-004 Requirement R4.

R2.5.4. The controls used to secure dial-up accessible connections.

R2.6. Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.

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

R3.1. For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.

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

R4. Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:

R4.1. A document identifying the vulnerability assessment process;

R4.2. A review to verify that only ports and services required for operations at these access points are enabled;

R4.3. The discovery of all access points to the Electronic Security Perimeter;

R4.4. A review of controls for default accounts, passwords, and network management community strings; and,

R4.5. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R5. Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005.

R5.1. The Responsible Entity shall ensure that all documentation required by Standard CIP-005 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005 at least annually.

R5.2. The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.

R5.3. The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008.

C. Measures

The following measures will be used to demonstrate compliance with the requirements of Standard CIP-005. Responsible entities may document controls either individually or by specified applicable grouping.

M1. Documents about the Electronic Security Perimeter as specified in Requirement R1.

M2. Documentation of the electronic access controls to the Electronic Security Perimeter(s), as specified in Requirement R2.

M3. Documentation of controls implemented to log and monitor access to the Electronic Security Perimeter(s) as specified in Requirement R3.

M4. Documentation of the Responsible Entity's annual vulnerability assessment as specified in Requirement R4.

M5. Access logs and documentation of review, changes, and log retention as specified in Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.1.1 Regional Reliability Organizations for Responsible Entities.

1.1.2 NERC for Regional Reliability Organization.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

1.3.1 The Responsible Entity shall keep logs for a minimum of ninety calendar days, unless longer retention is required pursuant to Standard CIP-008, Requirement R2.

1.3.2 The Responsible Entity shall keep other documents and records required by Standard CIP-005 from the previous full calendar year.

1.3.3 The compliance monitor shall keep audit records for three years.

1.4. Additional Compliance Information

1.4.1 Responsible Entities shall demonstrate compliance through self-certification or audit, as determined by the Compliance Monitor.

1.4.2 Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and approved by the designated senior manager or delegate(s). Duly authorized exceptions will not result in noncompliance. Refer to CIP-003 Requirement R3.

2. Levels of Noncompliance

2.1. Level 1:

2.1.1 All document(s) identified in CIP-005 exist, but have not been updated within ninety calendar days of any changes as required; or,

2.1.2 Access to less than 15% of electronic security perimeters is not controlled, monitored; and logged;

2.1.3 Document(s) exist confirming that only necessary network ports and services have been enabled, but no record documenting annual reviews exists; or,

2.1.4 At least one, but not all, of the Electronic Security Perimeter vulnerability assessment items has been performed in the last full calendar year.

2.2. Level 2:

2.2.1 All document(s) identified in CIP-005 but have not been updated or reviewed in the previous full calendar year as required; or,

2.2.2 Access to between 15% and 25% of electronic security perimeters is not controlled, monitored; and logged; or,

2.2.3 Documentation and records of vulnerability assessments of the Electronic Security Perimeter(s) exist, but a vulnerability assessment has not been performed in the previous full calendar year.

2.3. Level 3:

2.3.1 A document defining the Electronic Security Perimeter(s) exists, but there are one or more Critical Cyber Assets not within the defined Electronic Security Perimeter(s); or,

2.3.2 One or more identified non-critical Cyber Assets is within the Electronic Security Perimeter(s) but not documented; or,

2.3.3 Electronic access controls document(s) exist, but one or more access points have not been identified; or

2.3.4 Electronic access controls document(s) do not identify or describe access controls for one or more access points; or,

2.3.5 Electronic Access Monitoring:

2.3.5.1 Access to between 26% and 50% of Electronic Security Perimeters is not controlled, monitored; and logged; or,

2.3.5.2 Access logs exist, but have not been reviewed within the past ninety calendar days; or,

2.3.6 Documentation and records of vulnerability assessments of the Electronic Security Perimeter(s) exist, but a vulnerability assessment has not been performed for more than two full calendar years.

2.4. Level 4:

2.4.1 No documented Electronic Security Perimeter exists; or,

2.4.2 No records of access exist; or,

2.4.3 51% or more Electronic Security Perimeters are not controlled, monitored, and logged; or,

2.4.4 Documentation and records of vulnerability assessments of the Electronic Security Perimeter(s) exist, but a vulnerability assessment has not been performed for more than three full calendar years; or,

2.4.5 No documented vulnerability assessment of the Electronic Security Perimeter(s) process exists.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	D.2.3.1 — Change “Critical Assets,” to “Critical Cyber Assets” as intended.	03/24/06

A. Introduction

1. **Title:** Cyber Security — Physical Security of Critical Cyber Assets

2. **Number:** CIP-006-1

3. **Purpose:** Standard CIP-006 is intended to ensure the implementation of a physical security program for the protection of Critical Cyber Assets. Standard CIP-006 should be read as part of a group of standards numbered Standards CIP-002 through CIP-009. Responsible Entities should apply Standards CIP-002 through CIP-009 using reasonable business judgment.

4. **Applicability:**

   4.1. Within the text of Standard CIP-006, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Reliability Organizations.

   4.2. The following are exempt from Standard CIP-006:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002, identify that they have no Critical Cyber Assets.

5. **Effective Date:** June 1, 2006

B. Requirements

The Responsible Entity shall comply with the following requirements of Standard CIP-006:

R1. Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:

R1.1. Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.

R1.2. Processes to identify all access points through each Physical Security Perimeter and measures to control entry at those access points.

R1.3. Processes, tools, and procedures to monitor physical access to the perimeter(s).

R1.4. Procedures for the appropriate use of physical access controls as described in Requirement R3 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.

R1.5. Procedures for reviewing access authorization requests and revocation of access authorization, in accordance with CIP-004 Requirement R4.

R1.6. Procedures for escorted access within the physical security perimeter of personnel not authorized for unescorted access.

R1.7. Process for updating the physical security plan within ninety calendar days of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the physical security perimeter, physical access controls, monitoring controls, or logging controls.

R1.8. Cyber Assets used in the access control and monitoring of the Physical Security Perimeter(s) shall be afforded the protective measures specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirement R2 and R3, Standard CIP-007, Standard CIP-008 and Standard CIP-009.

R1.9. Process for ensuring that the physical security plan is reviewed at least annually.

R2. Physical Access Controls **—** The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:

R2.1. Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.

R2.2. Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.

R2.3. Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.

R2.4. Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.

R3. Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008. One or more of the following monitoring methods shall be used:

R3.1. Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.

R3.2. Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R2.3.

R4. Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:

R4.1. Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.

R4.2. Video Recording: Electronic capture of video images of sufficient quality to determine identity.

R4.3. Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R2.3.

R5. Access Log Retention — The responsible entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008.

R6. Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R2, R3, and R4 function properly. The program must include, at a minimum, the following:

R6.1. Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.

R6.2. Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R6.1.

R6.3. Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.

C. Measures

The following measures will be used to demonstrate compliance with the requirements of Standard CIP-006:

M1. The physical security plan as specified in Requirement R1 and documentation of the review and updating of the plan.

M2. Documentation identifying the methods for controlling physical access to each access point of a Physical Security Perimeter as specified in Requirement R2.

M3. Documentation identifying the methods for monitoring physical access as specified in Requirement R3.

M4. Documentation identifying the methods for logging physical access as specified in Requirement R4.

M5. Access logs as specified in Requirement R5.

M6. Documentation as specified in Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.1.1 Regional Reliability Organizations for Responsible Entities.

1.1.2 NERC for Regional Reliability Organization.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

1.3.1 The Responsible Entity shall keep documents other than those specified in Requirements R5 and R6.2 from the previous full calendar year.

1.3.2 The compliance monitor shall keep audit records for three calendar years.

1.4. Additional Compliance Information

1.4.1 Responsible Entities shall demonstrate compliance through self-certification or audit, as determined by the Compliance Monitor.

1.4.2 Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and approved by the designated senior manager or delegate(s). Duly authorized exceptions will not result in noncompliance. Refer to Standard CIP-003 Requirement R3.

1.4.3 The Responsible Entity may not make exceptions in its cyber security policy to the creation, documentation, or maintenance of a physical security plan.

1.4.4 For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall not be required to comply with Standard CIP-006 for that single access point at the dial-up device.

2. Levels of Noncompliance

2.1. Level 1:

2.1.1 The physical security plan exists, but has not been updated within ninety calendar days of a modification to the plan or any of its components; or,

2.1.2 Access to less than 15% of a Responsible Entity's total number of physical security perimeters is not controlled, monitored, and logged; or,

2.1.3 Required documentation exists but has not been updated within ninety calendar days of a modification.; or,

2.1.4 Physical access logs are retained for a period shorter than ninety days; or,

2.1.5 A maintenance and testing program for the required physical security systems exists, but not all have been tested within the required cycle; or,

2.1.6 One required document does not exist.

2.2. Level 2:

2.2.1 The physical security plan exists, but has not been updated within six calendar months of a modification to the plan or any of its components; or,

2.2.2 Access to between 15% and 25% of a Responsible Entity's total number of physical security perimeters is not controlled, monitored, and logged; or,

2.2.3 Required documentation exists but has not been updated within six calendar months of a modification; or

2.2.4 More than one required document does not exist.

2.3. Level 3:

2.3.1 The physical security plan exists, but has not been updated or reviewed in the last twelve calendar months of a modification to the physical security plan; or,

2.3.2 Access to between 26% and 50% of a Responsible Entity's total number of physical security perimeters is not controlled, monitored, and logged; or,

2.3.3 No logs of monitored physical access are retained.

2.4. Level 4:

2.4.1 No physical security plan exists; or,

2.4.2 Access to more than 51% of a Responsible Entity's total number of physical security perimeters is not controlled, monitored, and logged; or,

2.4.3 No maintenance or testing program exists.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** Cyber Security — Systems Security Management

2. **Number:** CIP-007-1

3. **Purpose:** Standard CIP-007 requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the non-critical Cyber Assets within the Electronic Security Perimeter(s). Standard CIP-007 should be read as part of a group of standards numbered Standards CIP-002 through CIP-009. Responsible Entities should interpret and apply Standards CIP-002 through CIP-009 using reasonable business judgment.

4. **Applicability:**

   4.1. Within the text of Standard CIP-007, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Reliability Organizations.

   4.2. The following are exempt from Standard CIP-007:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002, identify that they have no Critical Cyber Assets.

5. **Effective Date:** June 1, 2006

B. Requirements

The Responsible Entity shall comply with the following requirements of Standard CIP-007 for all Critical Cyber Assets and other Cyber Assets within the Electronic Security Perimeter(s):

R1. Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.

R1.1. The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.

R1.2. The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.

R1.3. The Responsible Entity shall document test results.

R2. Ports and Services — The Responsible Entity shall establish and document a process to ensure that only those ports and services required for normal and emergency operations are enabled.

R2.1. The Responsible Entity shall enable only those ports and services required for normal and emergency operations.

R2.2. The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).

R2.3. In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.

R3. Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003 Requirement R6, shall establish and document a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).

R3.1. The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.

R3.2. The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.

R4. Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software (“malware”) prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).

R4.1. The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.

R4.2. The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention “signatures.” The process must address testing and installing the signatures.

R5. Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.

R5.1. The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of “need to know” with respect to work functions performed.

R5.1.1. The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003 Requirement R5.

R5.1.2. The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.

R5.1.3. The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003 Requirement R5 and Standard CIP-004 Requirement R4.

R5.2. The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.

R5.2.1. The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.

R5.2.2. The Responsible Entity shall identify those individuals with access to shared accounts.

R5.2.3. Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).

R5.3. At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:

R5.3.1. Each password shall be a minimum of six characters.

R5.3.2. Each password shall consist of a combination of alpha, numeric, and “special” characters.

R5.3.3. Each password shall be changed at least annually, or more frequently based on risk.

R6. Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.

R6.1. The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.

R6.2. The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.

R6.3. The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008.

R6.4. The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.

R6.5. The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.

R7. Disposal or Redeployment — The Responsible Entity shall establish formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005.

R7.1. Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

R7.2. Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.

R7.3. The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.

R8. Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:

R8.1. A document identifying the vulnerability assessment process;

R8.2. A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;

R8.3. A review of controls for default accounts; and,

R8.4. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R9. Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007 at least annually. Changes resulting from modifications to the systems or controls shall be documented within ninety calendar days of the change.

C. Measures

The following measures will be used to demonstrate compliance with the requirements of Standard CIP-007:

M1. Documentation of the Responsible Entity's security test procedures as specified in Requirement R1.

M2. Documentation as specified in Requirement R2.

M3. Documentation and records of the Responsible Entity's security patch management program, as specified in Requirement R3.

M4. Documentation and records of the Responsible Entity's malicious software prevention program as specified in Requirement R4.

M5. Documentation and records of the Responsible Entity's account management program as specified in Requirement R5.

M6. Documentation and records of the Responsible Entity's security status monitoring program as specified in Requirement R6.

M7. Documentation and records of the Responsible Entity's program for the disposal or redeployment of Cyber Assets as specified in Requirement R7.

M8. Documentation and records of the Responsible Entity's annual vulnerability assessment of all Cyber Assets within the Electronic Security Perimeters(s) as specified in Requirement R8.

M9. Documentation and records demonstrating the review and update as specified in Requirement R9.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.1.1 Regional Reliability Organizations for Responsible Entities.

1.1.2 NERC for Regional Reliability Organization.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

1.3.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year.

1.3.2 The Responsible Entity shall retain security–related system event logs for ninety calendar days, unless longer retention is required pursuant to Standard CIP-008 Requirement R2.

1.3.3 The compliance monitor shall keep audit records for three calendar years.

1.4. Additional Compliance Information.

1.4.1 Responsible Entities shall demonstrate compliance through self-certification or audit, as determined by the Compliance Monitor.

1.4.2 Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and approved by the designated senior manager or delegate(s). Duly authorized exceptions will not result in non-compliance. Refer to Standard CIP-003 Requirement R3.

2. Levels of Noncompliance

2.1. Level 1:

2.1.1 System security controls are in place, but fail to document one of the measures (M1-M9) of Standard CIP-007; or

2.1.2 One of the documents required in Standard CIP-007 has not been reviewed in the previous full calendar year as specified by Requirement R9; or,

2.1.3 One of the documented system security controls has not been updated within ninety calendar days of a change as specified by Requirement R9; or,

2.1.4 Any one of:

- Authorization rights and access privileges have not been reviewed during the previous full calendar year; or,
- A gap exists in any one log of system events related to cyber security of greater than seven calendar days; or,
- Security patches and upgrades have not been assessed for applicability within thirty calendar days of availability.

2.2. Level 2:

2.2.1 System security controls are in place, but fail to document up to two of the measures (M1-M9) of Standard CIP-007; or,

2.2.2 Two occurrences in any combination of those violations enumerated in Noncompliance Level 1, 2.1.4 within the same compliance period.

2.3. Level 3:

2.3.1 System security controls are in place, but fail to document up to three of the measures (M1-M9) of Standard CIP-007; or,

2.3.2 Three occurrences in any combination of those violations enumerated in Noncompliance Level 1, 2.1.4 within the same compliance period.

2.4. Level 4:

2.4.1 System security controls are in place, but fail to document four or more of the measures (M1-M9) of Standard CIP-007; or,

2.4.2 Four occurrences in any combination of those violations enumerated in Noncompliance Level 1, 2.1.4 within the same compliance period.

2.4.3 No logs exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** Cyber Security — Incident Reporting and Response Planning

2. **Number:** CIP-008-1

3. **Purpose:** Standard CIP-008 ensures the identification, classification, response, and reporting of Cyber Security Incidents related to Critical Cyber Assets. Standard CIP-008 should be read as part of a group of standards numbered Standards CIP-002 through CIP-009. Responsible Entities should apply Standards CIP-002 through CIP-009 using reasonable business judgment.

4. **Applicability**

   4.1. Within the text of Standard CIP-008, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Reliability Organizations.

   4.2. The following are exempt from Standard CIP-008:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002, identify that they have no Critical Cyber Assets.

5. **Effective Date:** June 1, 2006

B. Requirements

The Responsible Entity shall comply with the following requirements of Standard CIP-008:

R1. Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan. The Cyber Security Incident Response plan shall address, at a minimum, the following:

R1.1. Procedures to characterize and classify events as reportable Cyber Security Incidents.

R1.2. Response actions, including roles and responsibilities of incident response teams, incident handling procedures, and communication plans.

R1.3. Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES ISAC either directly or through an intermediary.

R1.4. Process for updating the Cyber Security Incident response plan within ninety calendar days of any changes.

R1.5. Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.

R1.6. Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident.

R2. Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for three calendar years.

C. Measures

The following measures will be used to demonstrate compliance with the requirements of CIP-008:

M1. The Cyber Security Incident response plan as indicated in R1 and documentation of the review, updating, and testing of the plan

M2. All documentation as specified in Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.1.1 Regional Reliability Organizations for Responsible Entities.

1.1.2 NERC for Regional Reliability Organization.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

1.3.1 The Responsible Entity shall keep documentation other than that required for reportable Cyber Security Incidents as specified in Standard CIP-008 for the previous full calendar year.

1.3.2 The compliance monitor shall keep audit records for three calendar years.

1.4. Additional Compliance Information

1.4.1 Responsible Entities shall demonstrate compliance through self-certification or audit, as determined by the Compliance Monitor.

1.4.2 Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and approved by the designated senior manager or delegate(s). Duly authorized exceptions will not result in non-compliance. Refer to Standard CIP-003 Requirement R3.

1.4.3 The Responsible Entity may not take exception in its cyber security policies to the creation of a Cyber Security Incident response plan.

1.4.4 The Responsible Entity may not take exception in its cyber security policies to reporting Cyber Security Incidents to the ES ISAC.

2. Levels of Noncompliance

2.1. Level 1: A Cyber Security Incident response plan exists, but has not been updated within ninety calendar days of changes.

2.2. Level 2:

2.2.1 A Cyber Security Incident response plan exists, but has not been reviewed in the previous full calendar year; or,

2.2.2 A Cyber Security Incident response plan has not been tested in the previous full calendar year; or,

2.2.3 Records related to reportable Cyber Security Incidents were not retained for three calendar years.

2.3. Level 3:

2.3.1 A Cyber Security Incident response plan exists, but does not include required elements Requirements R1.1, R1.2, and R1.3 of Standard CIP-008; or,

2.3.2 A reportable Cyber Security Incident has occurred but was not reported to the ES ISAC.

2.4. Level 4: A Cyber Security Incident response plan does not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** Cyber Security — Recovery Plans for Critical Cyber Assets

2. **Number:** CIP-009-1

3. **Purpose:** Standard CIP-009 ensures that recovery plan(s) are put in place for Critical Cyber Assets and that these plans follow established business continuity and disaster recovery techniques and practices. Standard CIP-009 should be read as part of a group of standards numbered Standards CIP-002 through CIP-009. Responsible Entities should apply Standards CIP-002 through CIP-009 using reasonable business judgment.

4. **Applicability:**

4.1. Within the text of Standard CIP-009, "Responsible Entity" shall mean:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Interchange Authority

4.1.4 Transmission Service Provider

4.1.5 Transmission Owner

4.1.6 Transmission Operator

4.1.7 Generator Owner

4.1.8 Generator Operator

4.1.9 Load Serving Entity

4.1.10 NERC

4.1.11 Regional Reliability Organizations

4.2. The following are exempt from Standard CIP-009:

4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3 Responsible Entities that, in compliance with Standard CIP-002, identify that they have no Critical Cyber Assets.

5. **Effective Date:** June 1, 2006

B. Requirements

The Responsible Entity shall comply with the following requirements of Standard CIP-009:

R1. Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:

R1.1. Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).

R1.2. Define the roles and responsibilities of responders.

R2. Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.

R3. Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within ninety calendar days of the change.

R4. Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets. For example, backups may include spare electronic components or equipment, written documentation of configuration settings, tape backup, etc.

R5. Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is available. Testing can be completed off site.

C. Measures

The following measures will be used to demonstrate compliance with the requirements of Standard CIP-009:

M1. Recovery plan(s) as specified in Requirement R1.

M2. Records documenting required exercises as specified in Requirement R2.

M3. Documentation of changes to the recovery plan(s), and documentation of all communications, as specified in Requirement R3.

M4. Documentation regarding backup and storage of information as specified in Requirement R4.

M5. Documentation of testing of backup media as specified in Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.1.1 Regional Reliability Organizations for Responsible Entities.

1.1.2 NERC for Regional Reliability Organization.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

1.3.1 The Responsible Entity shall keep documentation required by Standard CIP-009 from the previous full calendar year.

1.3.2 The Compliance Monitor shall keep audit records for three calendar years.

1.4. Additional Compliance Information

1.4.1 Responsible Entities shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

1.4.2 Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and approved by the designated senior manager or delegate(s). Duly authorized exceptions will not result in non-compliance. Refer to Standard CIP-003 Requirement R3.

2. Levels of Noncompliance

2.1. Level 1:

2.1.1 Recovery plan(s) exist and are exercised, but do not contain all elements as specified in Requirement R1; or,

2.1.2 Recovery plan(s) are not updated and personnel are not notified within ninety calendar days of the change.

2.2. Level 2:

2.2.1 Recovery plan(s) exist, but have not been reviewed during the previous full calendar year; or,

2.2.2 Documented processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets do not exist.

2.3. Level 3:

2.3.1 Testing of information stored on backup media to ensure that the information is available has not been performed at least annually; or,

2.3.2 Recovery plan(s) exist, but have not been exercised during the previous full calendar year.

2.4. Level 4:

2.4.1 No recovery plan(s) exist; or,

2.4.2 Backup of information required to successfully restore Critical Cyber Assets does not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Interchange Information**
2. **Number:** INT-001-1
3. **Purpose:**

   To ensure that Interchange information is submitted to the NERC-identified reliability analysis service.
4. **Applicability:**

   4.1. Purchase-Selling Entities.

   4.2. Balancing Authorities.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:

R1.1. All Dynamic Schedules at the expected average MW profile for each hour.

R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:

R2.1. If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.

R2.2. For each bilateral Inadvertent Interchange payback.

C. Compliance

Not Specified.

D. Regional Differences

1. WECC Tagging Dynamic Schedules and Inadvertent Payback Waiver effective on November 21, 2002.
2. MISO Energy Flow Information Waiver effective on July 16, 2003.

Version History

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

A. Introduction

1. **Title:** **Interchange Transaction Implementation**

2. **Number:** INT-003-1

3. **Purpose:**

   To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations.

4. **Applicability**

   4.1. Balancing Authorities.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including:

R1.1.1. Interchange Schedule start and end time.

R1.1.2. Energy profile.

R1.2. If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

1. MISO Scheduling Agent Waiver dated November 21, 2002.
2. MISO Enhanced Scheduling Agent Waiver dated July 16, 2003.
3. MISO Energy Flow Information Waiver dated July 16, 2003.

Version History

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

A. Introduction

1. **Title:** **Dynamic Interchange Transaction Modifications**

2. **Number:** INT-004-1

3. **Purpose:** To ensure Dynamic Transfers are adequately tagged to be able to determine their reliability impacts.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Reliability Coordinators

   4.3. Transmission Operators

   4.4. Purchasing-Selling Entities

5. **Effective Date:** January 1, 2007

B. Requirements

R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.

R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs:

R2.1. The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±10%.

R2.2. The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±25 megawatt-hours.

R2.3. A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.

C. Measures

M1. The Sink Balancing Authority shall provide evidence that the responsible Purchasing-Selling Entity revised a tag when the deviation exceeded the criteria in INT-004 Requirement 2.

D. Compliance

1. **Compliance Monitoring Process**
Periodic tag audit as prescribed by NERC. For the requested time period, the Sink Balancing Authority shall provide the instances when Dynamic Schedule deviation exceeded the criteria in INT-004 R2 and shall provide evidence that the responsible Purchasing-Selling Entity submitted a revised tag.

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

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

1.3. Data Retention

Three months.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Not specified.

2.2. Level 2: Not specified.

2.3. Level 3: Not specified.

2.4. Level 4: Not specified.

E. Regional Differences

1. WECC Tagging Dynamic Schedules and Inadvertent Payback Waiver dated November 21, 2002.

Version History

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

A. Introduction

1. Title: **Interchange Authority Distributes Arranged Interchange**

2. Number: **INT-005-1**

3. Purpose: To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is distributed by an Interchange Authority such that Interchange information is available for reliability assessments.

4. Applicability

4.1. Interchange Authority.

5. Effective Date: January 1, 2007

B. Requirements

R1. Prior to the expiration of the time period defined in the Timing Table, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange.

R1.1. When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall be able to provide evidence that it has distributed the Arranged Interchange information to all reliability entities involved in the Interchange within the applicable time frame.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

1.3. Data Retention

The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a specific complaint of failure to perform R1. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate the Interchange Authority's distribution of all Arranged Interchange information to all reliability entities involved in an Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Interchange Authority.

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate that the Interchange Authority distributed the Arranged Interchange information to all reliability entities involved in that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not distributing information to all involved reliability entities as described in R1.

2.2. Level 2: Two occurrences[1] of not distributing information to all involved reliability entities as described in R1.

2.3. Level 3: Three occurrences[1] of not distributing information to all involved reliability entities as described in R1.

2.4. Level 4: Four or more occurrences[1] of not distributing information to all involved reliability entities as described in R1 or no evidence provided.

E. Regional Differences

None

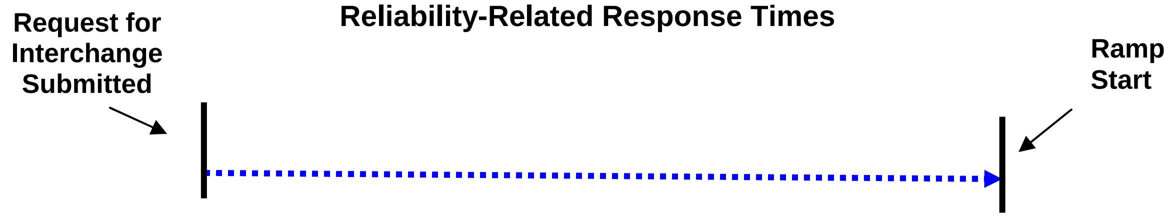
Version History

Version	Date	Action	Change Tracking

[1] This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.

Timing Table

Interchange Timeline with Minimum Reliability-Related Response Times



	A	B	C	D	
If **Actual Arranged Interchange (RFI) is Submitted**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments** **IA Verifies Reliability Data Complete**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**	**Minimum *Total* Reliability Period** **(Columns A through D)**
≤1 hour prior to ramp start	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA for all Interconnections except WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*15 minutes*
≤1 hour prior to ramp start	≤ 1 minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA for WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*10 minutes*
>1 hour to < 4 hours prior to ramp start	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start	*1 hour plus 1 minute*
≥ 4 hours prior to ramp start	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start	*4 hours*

A. Introduction

1. **Title:** **Response to Interchange Authority**
2. **Number:** **INT-006-1**
3. **Purpose:** To ensure that each Arranged Interchange is checked for reliability before it is implemented.
4. **Applicability**
    - **4.1.** Balancing Authority.
    - **4.2.** Transmission Service Provider.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. Prior to the expiration of the reliability assessment period defined in the Timing Table, Column B, the Balancing Authority and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.

R1.1. Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:

R1.1.1. Energy profile (ability to support the magnitude of the Interchange).

R1.1.2. Ramp (ability of generation maneuverability to accommodate).

R1.1.3. Scheduling path (proper connectivity of Adjacent Balancing Authorities).

R1.2. Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated.

C. Measures

M1. The Balancing Authority and Transmission Service Provider shall each provide evidence that it responded, relative to transitioning an Arranged Interchange to a Confirmed Interchange, to each request from an Interchange Authority within the reliability assessment period defined in the Timing Table, Column B.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility
Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

1.3. Data Retention

The Balancing Authority and Transmission Service Provider shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

The Balancing Authority and Transmission Service Provider shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authority, and Transmission Service Provider shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records and agreements for the audit period which indicate a reliability entity identified in R1 responded to all instances of the Interchange Authority's communication under Reliability Standard INT-005 Requirement 1 concerning the pending transition of an Arranged Interchange to Confirmed Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority, or Transmission Service Provider.

1.4.6 For specific complaints, agreements and those data and system log records associated with the specific Interchange event contained in the complaint which indicates a reliability entity identified in R1 has responded to the Interchange Authority's communication under INT-005 R1 concerning the pending transition of Arranged Interchange to Confirmed Interchange for that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not responding to the Interchange Authority as described in R1.

2.2. Level 2: Two occurrences[1] of not responding to the Interchange Authority as described in R1.

2.3. Level 3: Three occurrences[1] of not responding to the Interchange Authority as described in R1.

2.4. Level 4: Four or more occurrences[1] of not responding to the Interchange Authority as described in R1 or no evidence provided.

E. Regional Differences

None

Version History

Version	Date	Action	Change Tracking

[1] This does not include instances of not responding due to extenuating circumstances approved by the Compliance Monitor.

Timing Table

Interchange Timeline with Minimum Reliability-Related Response Times

	A	B	C	D	
If Actual Arranged Interchange (RFI) is Submitted	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments IA Verifies Reliability Data Complete**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**	**Minimum *Total* Reliability Period (Columns A through D)**
≤1 hour prior to ramp start	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA for all Interconnections except WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*15 minutes*
≤1 hour prior to ramp start	≤ 1 minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA for WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*10 minutes*
>1 hour to < 4 hours prior to ramp start	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start	*1 hour plus 1 minute*
≥ 4 hours prior to ramp start	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start	*4 hours*

A. Introduction

1. **Title:** **Interchange Confirmation**

2. **Number:** **INT-007-1**

3. **Purpose:** To ensure that each Arranged Interchange is checked for reliability before it is implemented.

4. **Applicability**

   4.1. Interchange Authority.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following:

R1.1. Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).

R1.2. All reliability entities involved in the Arranged Interchange are currently in the NERC registry.

R1.3. The following are defined:

R1.3.1. Generation source and load sink.

R1.3.2. Megawatt profile.

R1.3.3. Ramp start and stop times.

R1.3.4. Interchange duration.

R1.4. Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall show evidence that it has verified the Arranged Interchange information prior to the dissemination of the Confirmed Interchange.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.

   1.3. Data Retention

   The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate an Interchange Authority's verification that all Arranged Interchange was balanced and valid as defined in R1. The Compliance Monitor may request up to a three-month period of historical data ending with the date the request is received by the Interchange Authority.

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate an Interchange Authority's verification that an Arranged Interchange was balanced and valid as defined in R1 for that specific Interchange

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] where Interchange-related data was not verified as defined in R1.

2.2. Level 2: Two occurrences where Interchange-related data was not verified as defined in R1.

2.3. Level 3: Three occurrences where Interchange-related data was not verified as defined in R1.

2.4. Level 4: Four or more occurrences where Interchange-related data was not verified as defined in R1.

E. Regional Differences

None

[1] This does not include instances of not verifying due to extenuating circumstances approved by the Compliance Monitor.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Interchange Authority Distributes Status**

2. **Number:** **INT-008-1**

3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority.

4. **Applicability**

   4.1. Interchange Authority.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange.

R1.1. For Confirmed Interchange, the Interchange Authority shall also communicate:

R1.1.1. Start and stop times, ramps, and megawatt profile to Balancing Authorities.

R1.1.2. Necessary Interchange information to NERC-identified reliability analysis services.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall provide evidence that it has distributed the final status and Confirmed Interchange information specified in Requirement 1 to all Balancing Authorities, Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange within the time period defined in the Timing Table, Column C. If denied, the Interchange Authority shall tell all involved parties that approval has been denied.

M1.1 For each Arranged Interchange that includes a direct current tie, the Interchange Authority shall provide evidence that it has communicated the final status to the Balancing Authorities on both sides of the direct current tie, even if the Balancing Authorities are neither the Source nor Sink for the Interchange.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last non-compliance to R1.

   1.3. Data Retention

   The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance will be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate the Interchange Authority's distribution of all Arranged Interchange final status and Confirmed Interchange information to all entities involved in an Interchange per R1. The Compliance Monitor may request up to a three-month period of historical data ending with the date the request is received by the Interchange Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate that the Interchange Authority distributed the Arranged Interchange final status and Confirmed Interchange information to all entities involved in that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not distributing final status and information as described in R1.

2.2. Level 2: Two occurrences[1] of not distributing final status and information as described in R1.

2.3. Level 3: Three occurrences[1] of not distributing final status and information as described in R1.

2.4. Level 4: Four or more occurrences[1] of not distributing final status and information as described in R1 or no evidence provided.

E. Regional Differences

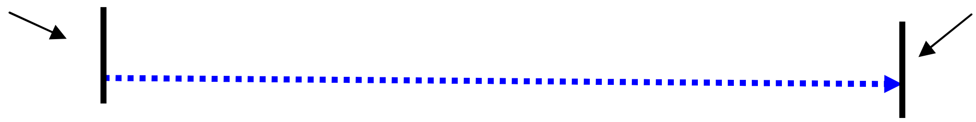
None

[1] This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.

Version History

Version	Date	Action	Change Tracking

Timing Table



	A	B	C	D	
If **Actual Arranged Interchange (RFI) is Submitted**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments** **IA Verifies Reliability Data Complete**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**	**Minimum *Total* Reliability Period** **(Columns A through D)**
≤1 hour prior to ramp start	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA for all Interconnections except WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*15 minutes*
≤1 hour prior to ramp start	≤ 1 minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA for WECC	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start	*10 minutes*
>1 hour to < 4 hours prior to ramp start	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start	*1 hour plus 1 minute*
≥ 4 hours prior to ramp start	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start	*4 hours*

A. Introduction

1. **Title:** **Implementation of Interchange**

2. **Number:** **INT-009-1**

3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority such that the Balancing Authorities implement the Interchange exactly as agreed upon in the Interchange confirmation process.

4. **Applicability**

   4.1. Balancing Authority.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.

C. Measures

M1. The Balancing Authority shall provide evidence that Implemented Interchange matches Confirmed Interchange as submitted by the Interchange Authority.

M2. Evidence shall demonstrate that the Interchange was implemented in the Balancing Authority's Area Control Error (ACE) equation, or the system that calculates the ACE equation. Evidence may be on a net basis or an individual Interchange basis.

M3. Balancing Authorities that are interconnected with a direct current tie shall demonstrate that the Interchange was implemented in the ACE equation or modeled as an equivalent generator/load within its area.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.

   1.3. Data Retention

   The Balancing Authority and Interchange Authority shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

   1.4. Additional Compliance Information

   Each Balancing Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

   Subsequent to the initial compliance review, compliance may be:

   1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Balancing Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authorities shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate a Balancing Authority implemented all instances of the Interchange Authority's communication under R1 concerning the implementation of a Confirmed Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicates a Balancing Authority implemented the Interchange Authority's communication under R1 concerning the implementation of the Confirmed Interchange for that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not implementing a Confirmed Interchange as described in R1.

2.2. Level 2: Two occurrences[1] of not implementing a Confirmed Interchange as described in R1.

2.3. Level 3: Three occurrences[1] of not implementing a Confirmed Interchange as described in R1.

2.4. Level 4: Four or more occurrences[1] of not implementing a Confirmed Interchange as described in R1 or no evidence provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

[1] This does not include instances of not implementing due to extenuating circumstances approved by the Compliance Monitor.

A. Introduction

1. **Title:** **Interchange Coordination Exemptions**

2. **Number:** **INT-010-1**

3. **Purpose:** Allow certain types of Interchange schedules to be initiated or modified by reliability entities, and to be exempt from compliance with other Interchange Standards under abnormal operating conditions.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Reliability Coordinator.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required.

R2. For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event.

R3. For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event.

C. Measures

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence it submitted Arranged Interchange per Requirement 1.

M2. The Reliability Coordinator that directs a modification to an existing Interchange shall have evidence that a directive was issued to submit the Arranged Interchange in accordance with Requirement 2.

M3. The Reliability Coordinator that directs the initiation of a new Interchange shall have evidence that a directive was issued to submit the Arranged Interchange in accordance with Requirement 3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last noncompliance to R1, R2, or R3.

1.3. Data Retention

The Balancing Authority and Reliability Coordinator shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Balancing Authority and Reliability Coordinator shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Balancing Authorities and Reliability Coordinators, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authority and Reliability Coordinator shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate a Balancing Authority or Reliability Coordinator acted in compliance with INT-010. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicates a Balancing Authority or Reliability Coordinator failed to act in compliance with INT-010.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 One occurrence of not submitting an Arranged Interchange as described in R1.

2.1.2 One occurrence of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.2. Level 2: There shall be a level two non-compliance if either of the following conditions is present:

2.2.1 Two occurrences of not submitting an Arranged Interchange as described in R1.

2.2.2 Two occurrences of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions is present:

2.3.1 Three occurrences of not submitting an Arranged Interchange as described in R1.

2.3.2 Three occurrences of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.4. Level 4: There shall be a level three non-compliance if any of the following conditions is present:

2.4.1 Four or more occurrences of not submitting an Arranged Interchange as described in R1.

2.4.2 Four or more occurrences of not directing the submittal of a new or modified Arranged Interchange as described in Requirements 2 or 3.

2.4.3 No evidence provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. Title: Reliability Coordination — Transmission Loading Relief

2. **Number:** IRO-006-3

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. **Proposed Effective Date:**

   E.2 effective upon BOT adoption.

   Changes to TLR 3b and 4 for IRO-006-2 to be announced.

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 Time Frame

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

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

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

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

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

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

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

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

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

   Section 5 of Attachment 1-IRO-006-1 requires that the "Per Generator Method without Counter Flow" methodology be utilized to calculate the portion of parallel flows on any Constrained Facility due to Network Integration (NI) transmission service and service to Native Load (NL) of each balancing authority.

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

   The Market Flow Calculation differs from the Per Generator Method in the following ways:

   - The contribution from all market area generators will be taken into account.
   - In the Per Generator Method, only generators having a GLDF greater than 5% are included in the calculation. Additionally, generators are included only when the sum of the maximum generating capacity at a bus is greater than 20 MW. The market flow calculations will use all positively impacting flows down to 0% with no threshold. Counter flows will not be included in the market flow calculation.

- The contribution of all market area generators is based on the present output level of each individual unit.
- The contribution of the market area load is based on the present demand at each individual bus.

By expanding on the Per Generator Method, the market flow calculation evolves into a methodology very similar to the "Per Generator Method" method, while providing increased Interchange Distribution Calculator (IDC) granularity. Counter flows are also calculated and tracked in order to account for and recognize that the either the positive market flows may be reduced or counter flows may be increased to provide appropriate relief on a flowgate.

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

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

Appendix B "Transaction Curtailment Formula" details the formula used to apply a weighted impact to each non-firm tagged Interchange Transaction (Priorities 1 thru 6) for the purposes of Curtailment by the IDC. For the purpose of Curtailment, the non-firm market flow impacts (Priorities 2 and 6) submitted to the IDC by SPP should be curtailed pro-rata as is done for Interchange Transaction using firm transmission service. This is because several of the values needed to assign a weighted impact using the process listed in Appendix B will not be available:

- Distribution Factor (no tag to calculate this value from)
- Impact on Interface value (cannot be calculated without Distribution Factor)
- Impact Weighting Factor (cannot be calculated without Distribution Factor)
- Weighted Maximum Interface Reduction (cannot be calculated without Distribution Factor)
- Interface Reduction (cannot be calculated without Distribution Factor)
- Transaction Reduction (cannot be calculated without Distribution Factor)

While the non-firm market flow impacts submitted to the IDC are to be curtailed pro rata, the impacting non-firm tagged Interchange Transactions could still use the existing processes to assign the weighted impact value.

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

Under the header "IDC Calculations and Reporting" in Section E2 of Appendix E to Attachment 1-IRO-006-1, the following requirement exists: "In a TLR Level 3a the Interchange Transactions using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status. Solely for the purpose of identifying which Interchange Transactions to be loaded under a TLR 3a, various MW levels of an Interchange Transaction may be in different sub-priorities. The sub-priorities are shown in the following table:

Priority	Purpose	Explanation and Conditions
S1	To allow a flowing Interchange Transaction to maintain or reduce its current MW amount in accordance with its energy profile.	The MW amount is the lowest between currently flowing MW amount and the next-hour schedule. The currently flowing MW amount is determined by the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.
S2	To allow a flowing Interchange Transaction that has been curtailed or halted by TLR to reload to the *lesser* of its current-hour MW amount or next-hour schedule in accordance with its energy profile.	The Interchange Transaction MW amount used is determined through the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.
S3	To allow a flowing Transaction to increase from its current-hour schedule to its next-hour schedule in accordance with its energy profile.	The MW amounts used in this sub-priority is determined by the e-tag ENERGY PROFILE table. If the calculated amount is negative, zero is used instead.
S4	To allow a Transaction that had never started and was submitted to the Tag Authority after the TLR (level 2 or higher) has been declared 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.

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

These market flow impacts for current hour and next hour will be separated into their appropriate priorities and provided to the IDC by SPP. The market flows will then be represented and made available for curtailment under the appropriate TLR Levels.

Even though these market flow impacts (separated into appropriate priorities) will not be represented by conventional “tags,” the impacts and their desired levels will still be provided to the IDC for current hour and next hour. Therefore, for the purposes of reallocation, a sub-priority (S1 thru S4) should be assigned to these market flow impacts by the NERC IDC as follows, using comparable logic as would be used if the impacts were in fact tagged transactions.

Priority	Purpose	Explanation and Conditions
S1	To allow existing market flow to	The currently flowing MW amount is

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

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

Transmission Loading Relief Procedure — Eastern Interconnection

Purpose

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

Applicability

This standard only applies to the Eastern Interconnection.

1. Transmission Loading Relief (TLR) Procedure

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Impacts of questionable IDC results may include:

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

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

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

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

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

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

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

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

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

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

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

2. Transmission Loading Relief (TLR) Levels

Introduction

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

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

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

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

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

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

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

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

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

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

2.2.3. TLR Level 2 is a transient state, which requires a quick decision to proceed to higher TLR Levels (3 and above) to allow Interchange Transactions to be implemented according to their transmission reservation priority. The time for being in TLR Level 2 should be no more than 30 minutes, with the understanding that there may be circumstances where this time may be exceeded. If the time in TLR Level 2 exceeds 30 minutes, the Reliability Coordinator shall document this action on the TLR Log.

2.3. TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service

2.3.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3a:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.
- The Transmission Provider has previously approved a higher priority Point-to-Point Transmission Service reservation over which a Transmission Customer wishes to begin an Interchange Transaction.

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

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

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

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

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

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

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

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

2.4. TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation

2.4.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3b**:**

- One or more transmission facilities are operating above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.

2.4.2. Curtailment procedures to mitigate an SOL or IROL. The Reliability Coordinator shall curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold as specified in Section 3, "Interchange Transaction Curtailment Order**"** in the current hour to mitigate an SOL or IROL as well as reallocating, in accordance with Section 6 of this document, to a determined flow for the top of the next hour.

The Reliability Coordinator shall allow Interchange Transactions using Firm Point-to-Point Transmission Service to start if they are submitted to the IDC within specific time limits as explained in Section 7 "Interchange Transaction Curtailments during TLR Level 3b."

2.5. TLR Level 4 — Reconfigure Transmission

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

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

2.5.2. Holding new Interchange Transactions. The Reliability Coordinator shall hold all new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold during the period of the SOL or IROL Violation. The Reliability Coordinator shall allow Interchange Transactions using Firm Point-to-Point Transmission Service to start if they are submitted to the IDC by 25 minutes past the hour or the time at which the TLR

Level 4 is called, whichever is later. See Appendix E, Section E2 – Timing Requirements.

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

2.6. TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service

2.6.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 5a**:**

- The transmission system is secure.
- One or more transmission facilities are at their SOL or IROL.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- The Transmission Provider has been requested to begin an Interchange Transaction using previously arranged Firm Transmission Service that would result in a SOL or IROL violation.
- No further transmission reconfiguration is possible or effective.

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

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

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

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

2.7. TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation

2.7.1. The Reliability Coordinator shall use following circumstances to establish the need for entering TLR Level 5b**:**

- One or more Transmission Facilities are operating above their SOL or IROL, or
- Such operation is imminent, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- No further transmission reconfiguration is possible or effective.

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

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

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

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

2.8. TLR Level 6 — Emergency Procedures

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

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

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

2.9. TLR Level 0 — TLR concluded

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

3. Interchange Transaction Curtailment Order for use in TLR Procedures

3.1. Priority of Interchange Transactions

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

Transmission Service Priorities

Priority 0. Next-hour Market Service — NX*

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

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

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

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

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

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

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

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

3.2. Curtailment of Interchange Transactions Using Non-firm Transmission Service

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

3.2.1.1. TLR Level 3a. Enable Interchange Transactions using a higher Transmission reservation priority to be implemented, or

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

3.3. Curtailment of Interchange Transactions Using Firm Transmission Service

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

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

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

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

Introduction

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

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

4.1. Constraints ON the Contract Path

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

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

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

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

4.2. Constraints OFF the Contract Path

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

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

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

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

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

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

Introduction

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

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

5.1. Requirements

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

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

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

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

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

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

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

5.2. Calculation Method

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

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

Introduction

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

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

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

6.1. Requirements

The basic requirements for Transaction Reallocation are as follows:

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

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

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

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

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

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

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

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

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

6.2. Communication and Timing Requirements

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

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

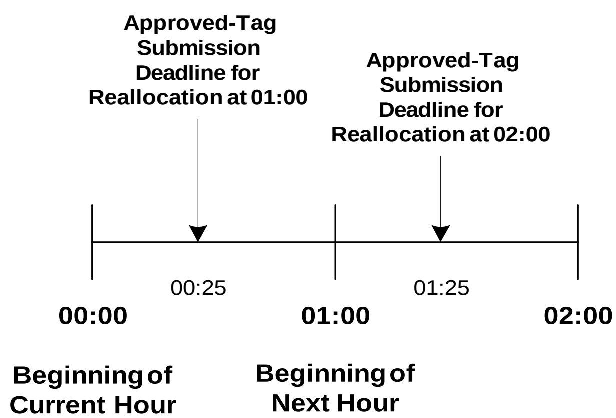


Figure 1 - Timeline showing Approved-tag Submission Deadline for Reallocation

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

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

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

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

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

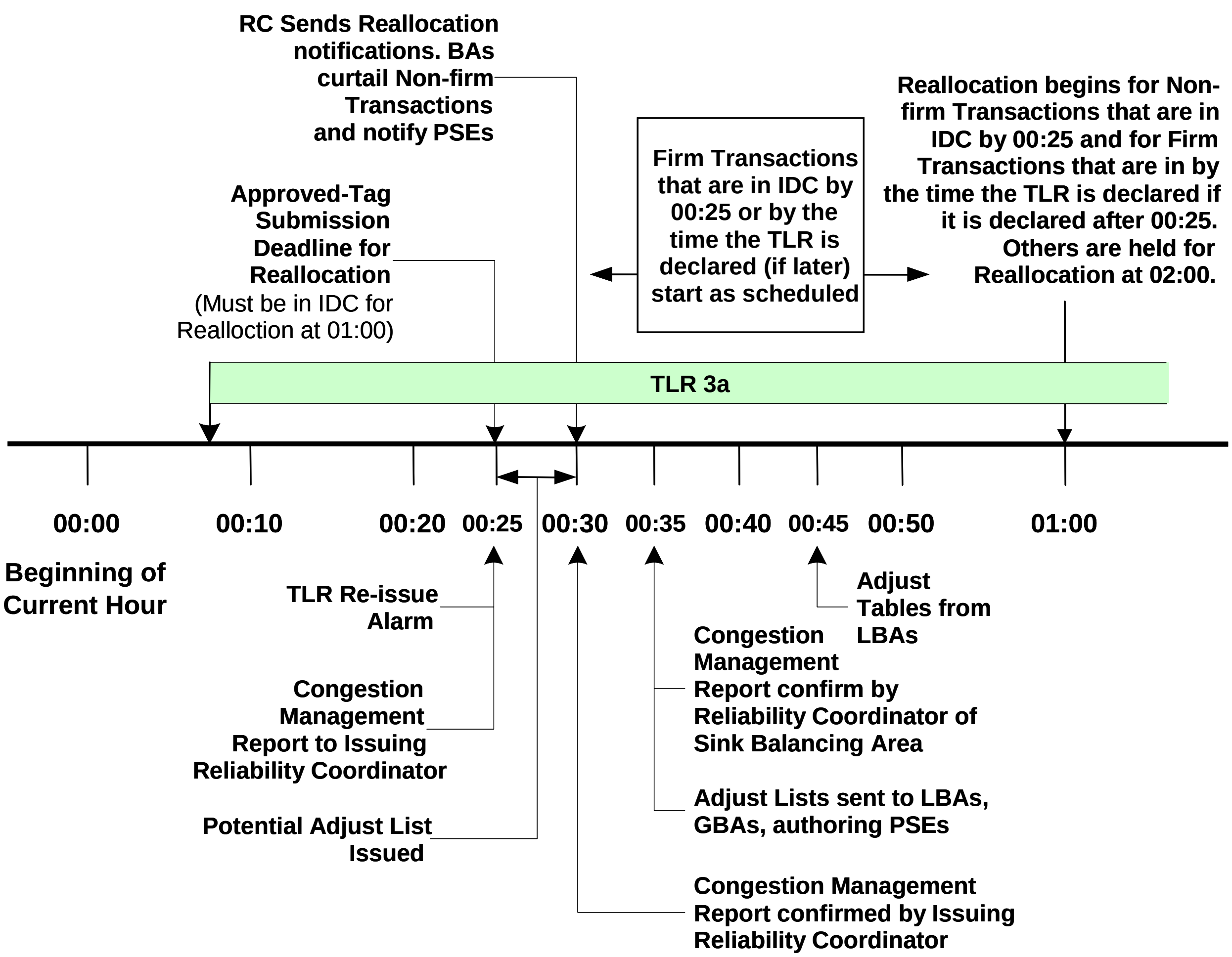


Figure 2 — Reallocation Timing for TLR 3a Called at 00:08

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

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

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

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

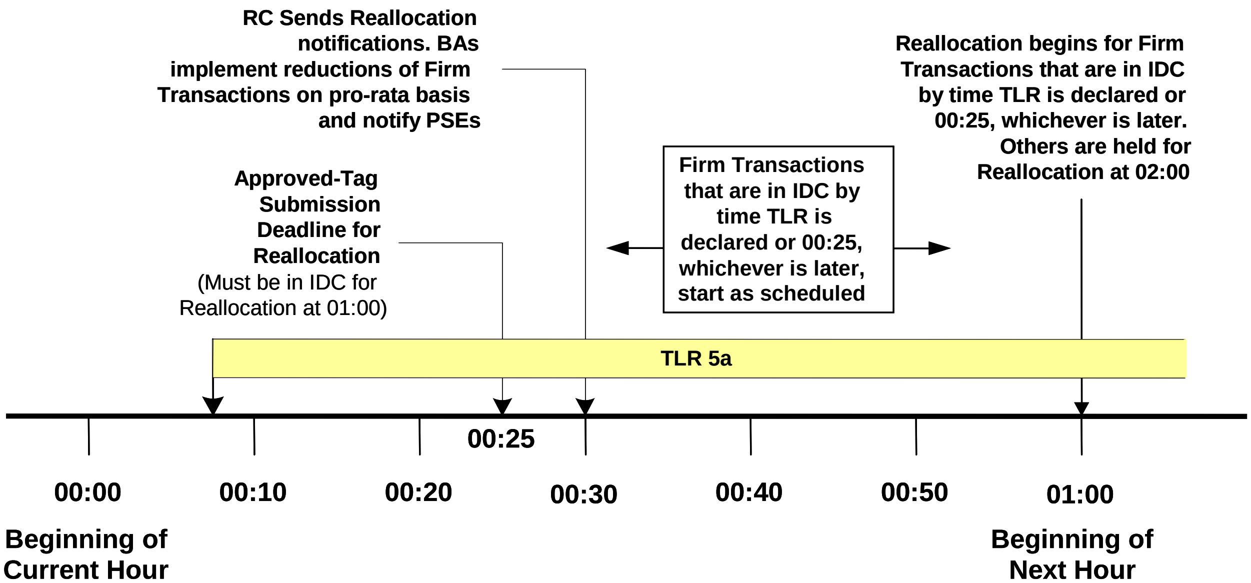


Figure 3 — Reallocation timing for TLR 5a called at 00:08.

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

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

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

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

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

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

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

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

Discussion: A Reliability Coordinator calls a TLR 2 or 3a whenever it deems necessary to indicate that a transmission facility is approaching its SOL or IROL. It is envisioned, though not required, that a TLR 2 or 3a is preceded by a period of a TLR 1 declaration, hence Transmission Customers should normally have advance notice of a potential constraint. For example, a TLR 3a initiated during the period 01:00 to 01:25 would allow the Purchasing-Selling Entity to submit a Tag for entry into the IDC by the Approved-Tag Submission Deadline for Reallocation at 02:00. See Figure 4. However, the preferred time period to declare a TLR 3a or 5a would be between 00:40 (when tags for Next Hour Market have been submitted) and 01:15. This will allow the Transmission Customers a range of 15 to 35 minutes to prepare and submit tags. (Note: In this situation, the Reliability Coordinator would need to reissue the TLR 3a at 01:00.)

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

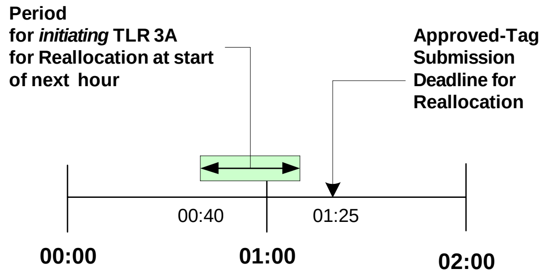


Figure 4. "Ideal" time for issuing TLR 3a for Reallocation at 02:00.

7. Interchange Transaction Curtailments During TLR Level 3b

Introduction

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

TLR Level 3b curtails Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold in the current hour while Reallocating to a determined flow for the top of the next hour (See **Requirement 2.4, "TLR Level 3b.")**.

Requirements

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

7.2. The Reliability Coordinator shall consider only those Interchange Transactions at or above the Curtailment Threshold for curtailment or holding.

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

7.4. The Reliability Coordinator shall Reallocate Interchange Transactions using Non-firm Point-to-Point Transmission Service in accordance with Section 6 of this document for the next hour to maintain the desired flow using Reallocation in accordance with the following timing specification:

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

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

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

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

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

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

7.7. The IDC shall issue ADJUST Lists to the Generation and Load Balancing Authority Areas and the Purchasing-Selling Entity who submitted the tag. The ADJUST List will include:

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

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

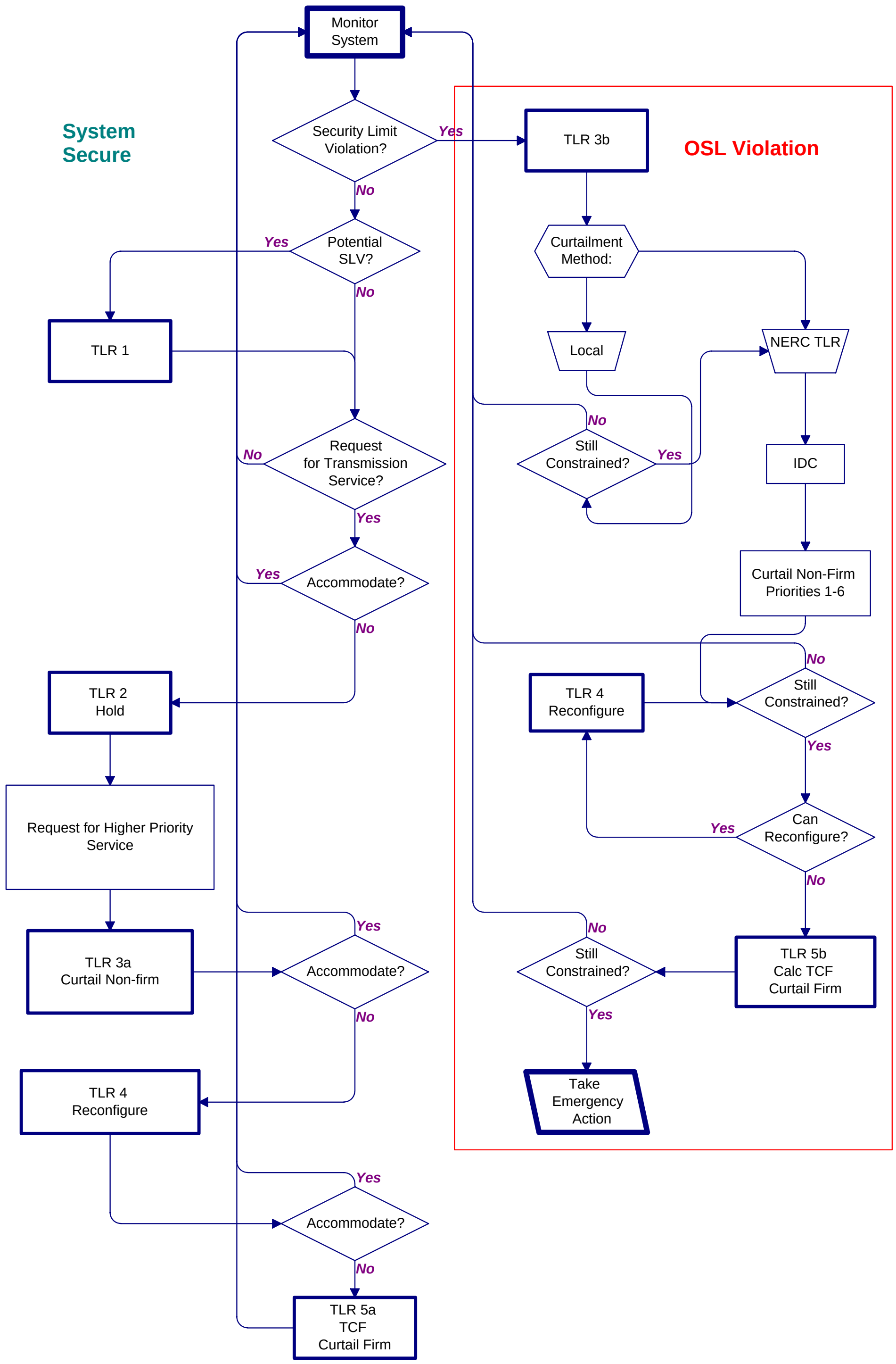
7.8. The Sink Balancing Authority shall send the ADJUST Lists back to the IDC as soon as possible to ensure the most accurate calculations for actions subsequent to the TLR 3b being called.

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

Appendices for Transmission Loading Relief Standard

Appendix A. Transaction Management and Curtailment Process

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



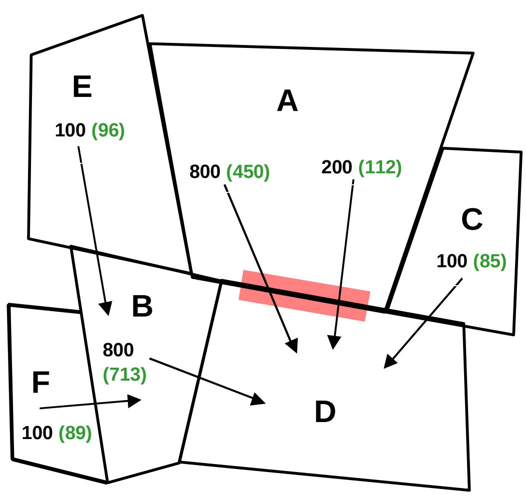
Appendix B. Transaction Curtailment Formula

Example

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

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

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



Appendix C. Sample NERC Transmission Loading Relief Procedure Log

SAVE FILE DIRECTORY:

NERC TRANSMISSION LOADING RELIEF (TLR) PROCEDURE LOG

FILE SAVED AS: .XLS

INCIDENT:	DATE:	IMPACTED RELIABILITY COORDINATOR	ID NO:

INITIAL CONDITIONS

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

TLR Levels

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

Priorities

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

TLR ACTIONS

LEVEL	TIME	Priority	TLR 3,5 No. TX Curtail	TLR 3,5 MW Curtai	MW Flow Limiting Element Present	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 Transmission Service

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

Example of Results of Calculation Method

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

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

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

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

Appendix E. How the IDC Handles Reallocation

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

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

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

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

Information posted from IDC to NERC TLR website.

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

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

3. Lowest priority of Interchange Transactions (marginal "bucket") to be Reloaded/Reallocated next-hour on each TLR Constrained Facility will be posted on NERC TLR website. This will provide an indication to the market of priority of Interchange Transactions that may be Reloaded/Reallocated the following hours.

IDC Logic, IDC Report, and Timing

1. The Reliability Coordinator will run the IDC the Reloading/Reallocation report at approximately 00:26. The IDC will prompt the Reliability Coordinator to enter a maximum loading value. The IDC will alarm if the Reliability Coordinator does not enter this value and issue a report by 00:30 or change from TLR 3a Level. The Report will be distributed to Balancing Authorities and Transmission Operators at 00:30. This process repeats every hour as long as the approved tag submission deadline for Reallocation is in effect (or until the TLR level is reduced to 1 or 0).

2. For Interchange Transactions in the restricted directions, tags must be submitted to the IDC by the approved tag submission deadline for Reallocation to be considered for Reallocation next-hour. The time stamp by the Tag Authority is regarded the official tag submission time.

3. Tags submitted to IDC after the approved tag submission deadline for Reallocation will not be allowed to start or increase but will be considered for Reallocation the next hour.

4. Interchange Transactions in restricted directions that are not indicated as "PROCEED" on the Reload/Reallocation Report will not be permitted to start or increase next hour.

Reloading/Reallocation Transaction Status

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

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

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

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

Reallocation/Reloading Priorities

1. Interchange Transaction candidates are ranked for loading and curtailment by priority as per Section 4, "Principles for Mitigating Constraints On and Off the Contract Path." This is called the "Constrained Path Method," or CPM. (secondary, hourly, daily, … firm etc). Interchange Transactions are curtailed and loaded pro-rata within priority level per TLR algorithm.

2. Reloading/Reallocation of Interchange Transactions are prioritized first by priority per CPM. E-Tags must be submitted to the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is scheduled to start or increase to be considered for Reallocation.

3. During Reloading/Reallocation, Interchange Transactions using lower priority Transmission Service will be curtailed pro-rata to allow higher priority transactions to reload, increase, or start. Equal priority Interchange Transactions will not reload, start, or increase by pro-rata Curtailment of other equal priority Interchange Transactions.

4. Reloading of Interchange Transactions using Non-firm Transmission Service with CURTAILED Status will take precedence over starting or increasing of Interchange Transactions using Non-firm Transmission Service of the same priority with PENDING Statuses.

5. Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled under TLR 3a as long as their E-Tag was received by the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is due to start or increase, regardless of whether the E-tag was submitted to the Tag Authority prior to TLR 2 or higher being declared or not. If this is the initial issuance of the TLR 3a, Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled as long as their E-Tag was received by the IDC by the time the TLR is declared.

Total Flow Value on a Constrained Facility for Next Hour

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

- Present constrained facility loading, present level of Interchange Transactions, and Balancing Authorities NNative Load responsibility (TLR Level 5a) impacting the Constrained Facility,

- SOLs or IROLs, known interchange impacts and Balancing Authority NNative Load responsibility (TLR Level 5a) on the Constrained Facility the next hour, and

- Interchange Transactions scheduled to begin the next hour.

2. The Reliability Coordinator will enter a maximum loading value for the constrained facility into the IDC as part of issuing the Reloading/Reallocation report.

3. The Reliability Coordinator is allowed to call for TLR 3a or 5a when approaching a SOL or IROL to allow maximum transactional flow next hour, and to manage flows without violating transmission limits.

4. The simultaneous curtailment and Reallocation for a Constrained Facility is allowed. This reduces the flow over the Constrained Facility while allowing Interchange Transactions using higher priority Transmission Service to start or increase the next hour. This may be used to accommodate change in flow next-hour due to changes other than Point-to-Point Interchange Transactions while respecting the priorities of Interchange Transactions flowing and scheduled to flow the next hour. The intent is to reduce the need for using TLR 3b, which prevents new Interchange Transactions from starting or increasing the next hour.

5. The Reliability Coordinator must allow Interchange Transactions to be reloaded as soon as possible. Reloading must be in an orderly fashion to prevent a SOL or IROL violation from (re)occurring and requiring holding or curtailments in the restricted direction.

E2. Timing Requirements

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

1. In order for the IDC to be reasonably certain that a TLR Level 3a or 5a re-allocation/reloading report in which all tags submitted by the approved tag submission deadline for Reallocation are included, the report must be generated no earlier than 00:25 to allow the 10-minute approval time for Transactions that start next hour.

2. In order to allow a Reliability Coordinator to declare a TLR Level 3a or 5a at any time during the hour, the TLR declaration and Reallocation/Reloading report distribution will be treated as independent processes by the IDC. That is, a Reliability Coordinator may declare a TLR Level 3a or 5a at any time during the course of an hour. However, if a TLR Level 3a or 5a is declared for the next hour prior to 00:25 (see Figure 5 at right), the Reallocation/Reloading report that is generated will be made available to the issuing Reliability Coordinator only for previewing purposes, and cannot be distributed to the other Reliability Coordinators or the market. Instead, the issuing Reliability Coordinator will be reminded by an IDC alarm at 00:25 to generate a new Reallocation/Reloading report that will include all tags submitted prior to the approved tag submission deadline for Reallocation.

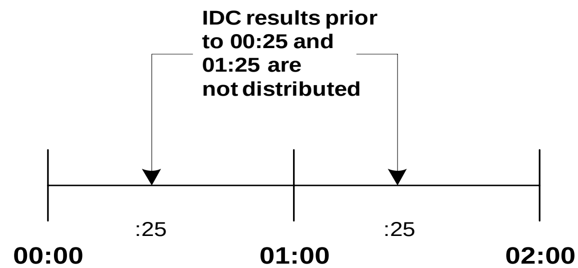


Figure 5 - IDC report may be run prior to 00:25, but results are not distributed.

3. A TLR Level 3a or 5a Reallocation/Reloading report must be confirmed by the issuing Reliability Coordinator prior to 00:30 in order to provide a minimum of 30 minutes for the Reliability Coordinators with tags sinking in its Reliability Area to coordinate the Reallocation and Reloading with the Sink Balancing Authorities. This provides only 5 minutes (from 00:25 to 00:30) for the issuing Reliability Coordinator to generate a Reallocation/Reloading report, review it, and approve it.

4. The TLR declaration time will be recorded in the IDC for evaluating transaction sub-priorities for Reallocation/Reloading purposes (see Subpriority Table, in the **IDC Calculations and Reporting** section below).

Re-Issuing of a TLR Level 2 or Higher

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

IDC Assistance with Next Hour Point-to-Point Transactions

In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour for a TLR level 3a or 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour. In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour during a TLR level 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour as well as Balancing Authority with flows due to service to Network Customers and Native Load. The Reliability Coordinator will then be requested to provide the total incremental or decremental MW amount of flow through the Constrained Facility that can be allowed for the next hour. The value entered by the Reliability Coordinator and the

IDC-calculated amounts will be used by the IDC to identify the relief/reloading amounts (delta incremental flow value) on the constrained facility. The IDC will determine the Transactions to be reloaded, reallocated, or curtailed to make room for the Transactions using higher priority Transmission Service. The following examples show the calculation performed by IDC to identify the "delta incremental flow:"

Example 1

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

Example 2

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

Example 3

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

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

IDC Calculations and Reporting

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

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

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

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

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

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

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

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

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

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

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

Tag Reloading for TLR Levels 1 and 0

When a TLR Level 1 or 0 is issued, the Constrained Facility is no longer under SOL or IROL violation and all Interchange Transactions are allowed to flow. In order to provide the Reliability Coordinators with a view of the Interchange Transactions that were halted or curtailed on previous TLR actions (level 2 or higher) and are now available for reloading, the IDC provides such information in the TLR report.

New Tag Alarming

Those Interchange Transactions that are at or above the Curtailment Threshold and are *not* candidates for Reallocation because the tags for those Transactions were not submitted by the approved tag submission deadline for Reallocation will be flagged as HOLD and must not be permitted to start or increase during the next hour. To alert Reliability Coordinators of those Transactions required to be held, the IDC will generate a report (for viewing within the IDC only) at various times. The report will include a list of all HOLD Transactions. In order not to overwhelm the Reliability Coordinator with alarms, only those who issued the TLR and those whose Transactions sink within their Reliability Area will be alarmed. An alarm will be issued for a given tag only once and will be issued for all TLR levels for which halting new Transactions is required: TLR Level 2, 3a, 3b, 5a and 5b.

Tag Adjustment

The Interchange Transactions with statuses of HOLD, CURTAILED or PROCEED must be adjusted by a Tag Authority or Tag Approval entity. Without the tag adjustments, the IDC will assume that Interchange Transactions were not curtailed/held and are flowing at their specified schedule amounts.

1. Interchange Transactions marked as CURTAILED should be adjusted to a cap equal to, or at the request of the originating PSE, less than the reallocated amount (shown as the MW CAP on the IDC report). This amount may be zero if the Transaction is fully curtailed.
2. Interchange Transaction marked as PROCEED should be adjusted to reload (NULL or to its MW level in accordance with its Energy Profile in the adjusted MW in the E-Tag) if the Interchange Transaction has been previously adjusted; otherwise, if the Interchange Transaction is flowing in full, the Tag Authority need not issue an adjust.
3. Interchange Transactions marked as HOLD should be adjusted to 0 MW.

Special Tag Status

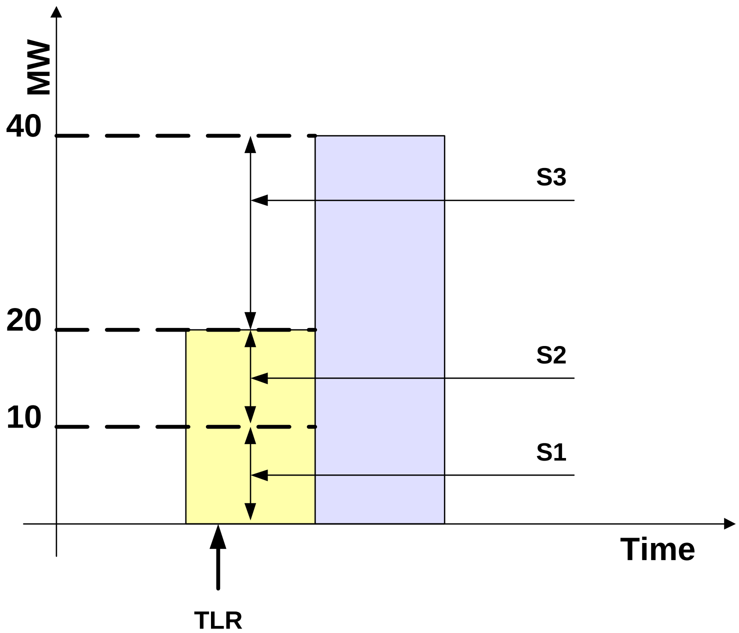
There are cases in which a tag may be marked with a composite state of ATTN_REQD to indicate that tag Authority/Approval failed to communicate or there is an inconsistency between the validation software of different tag Authority/Approval entities. In this situation, the tag is no longer subject to passive approval and its status change to IMPLEMENT may take longer than 10 minutes. Under these circumstances, the IDC may have a tag that is issued prior to the Tag Submittal Deadline that will not be a candidate for Reallocation. Such tags, when approved by the Tag Authority, will be marked as HOLD and must be halted.

Transaction Sub-Priority Examples

The following describes examples of Interchange Transactions using Non-firm Transmission Service sub-priority setting for an Interchange Transaction under different circumstances of current-hour and next-hour schedules and active MW flowing as modified by tag adjust table in E-Tag.

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

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

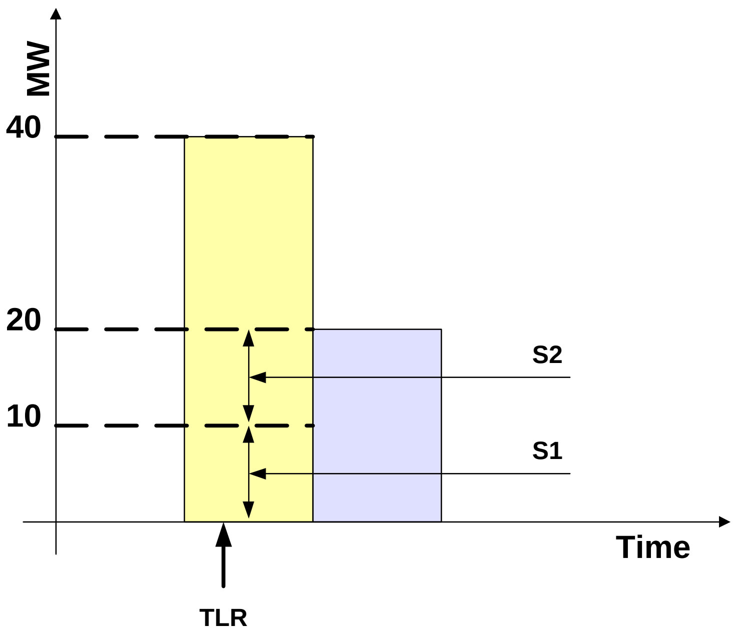


Sub-priorities for Transaction MW:

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

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

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

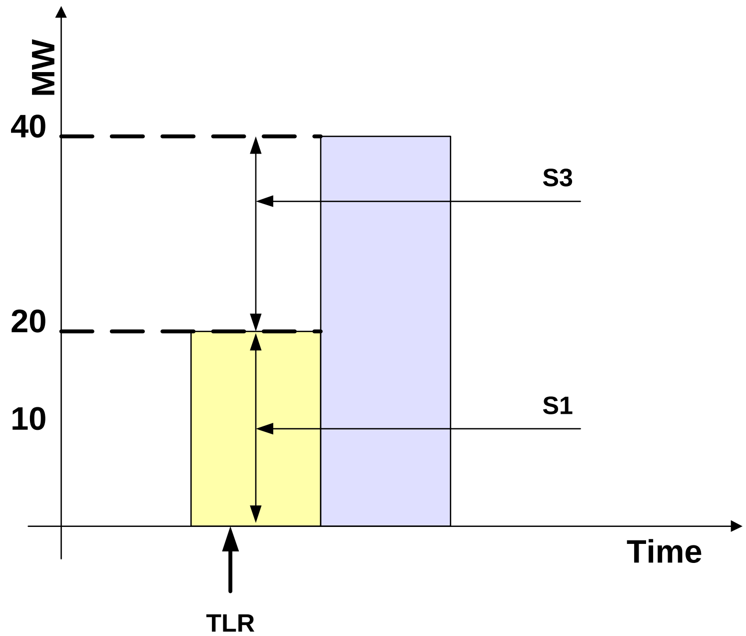


Sub-priorities for Transaction MW:

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

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

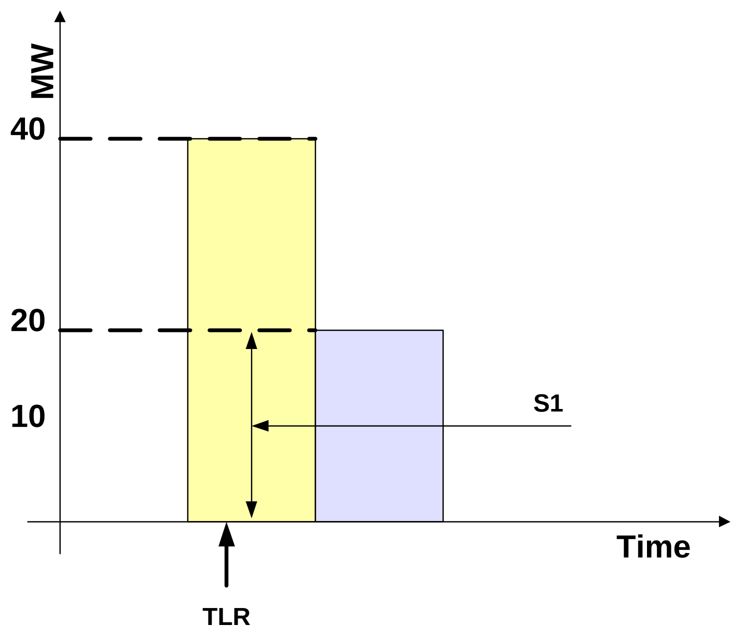
Energy Profile: Current hour	20 MW
Actual flow following curtailment: Current hour	20 MW (no curtailment)
Energy Profile: Next hour	40 MW



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

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

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

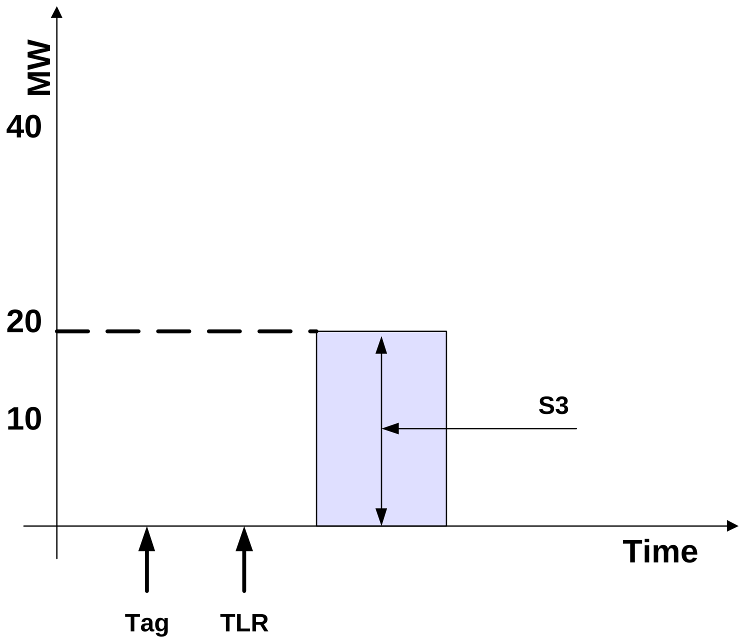


Sub-priorities for Transaction MW:

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

Example 5 — TLR Issued before Transaction was scheduled to start

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



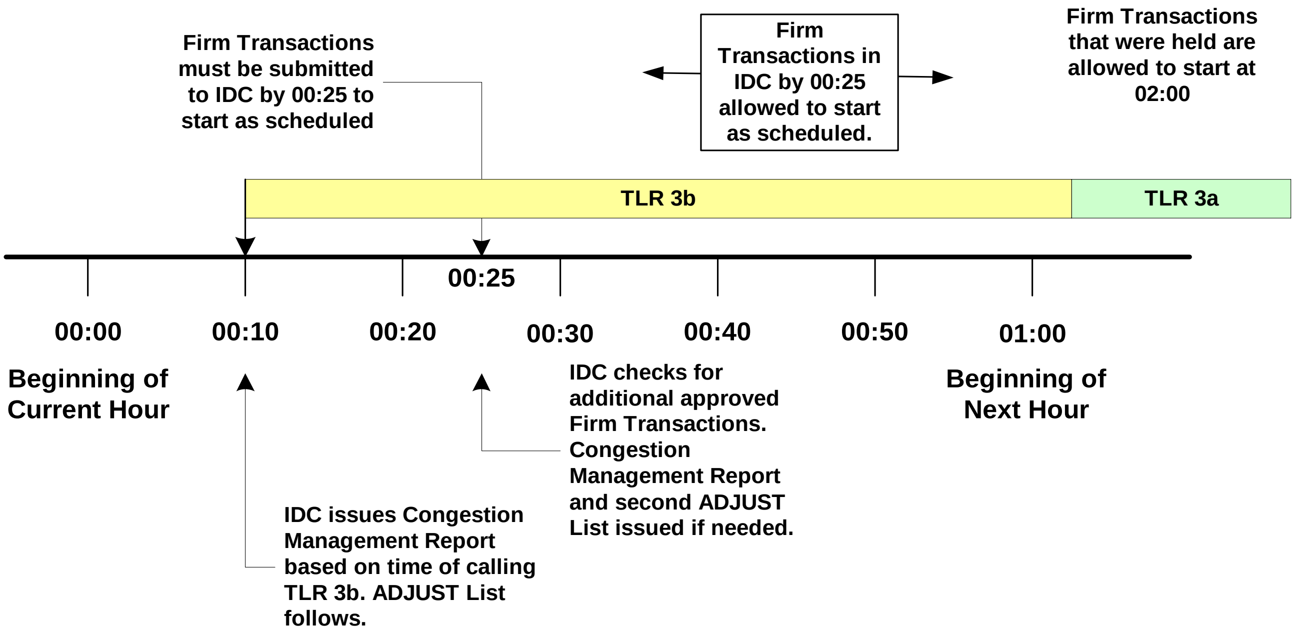
Sub-Priority	*MW Value*	*Explanation*
S1	0 MW	Transaction was not allowed to start
S2	+0 MW	Transaction was not allowed to start
S3	+20 MW	Next-hour Energy Profile is 20MW
S4	+0	Tag submitted prior to TLR

Appendix F. Considerations for Interchange Transactions

Using Firm Point-to-Point Transmission Service

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

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



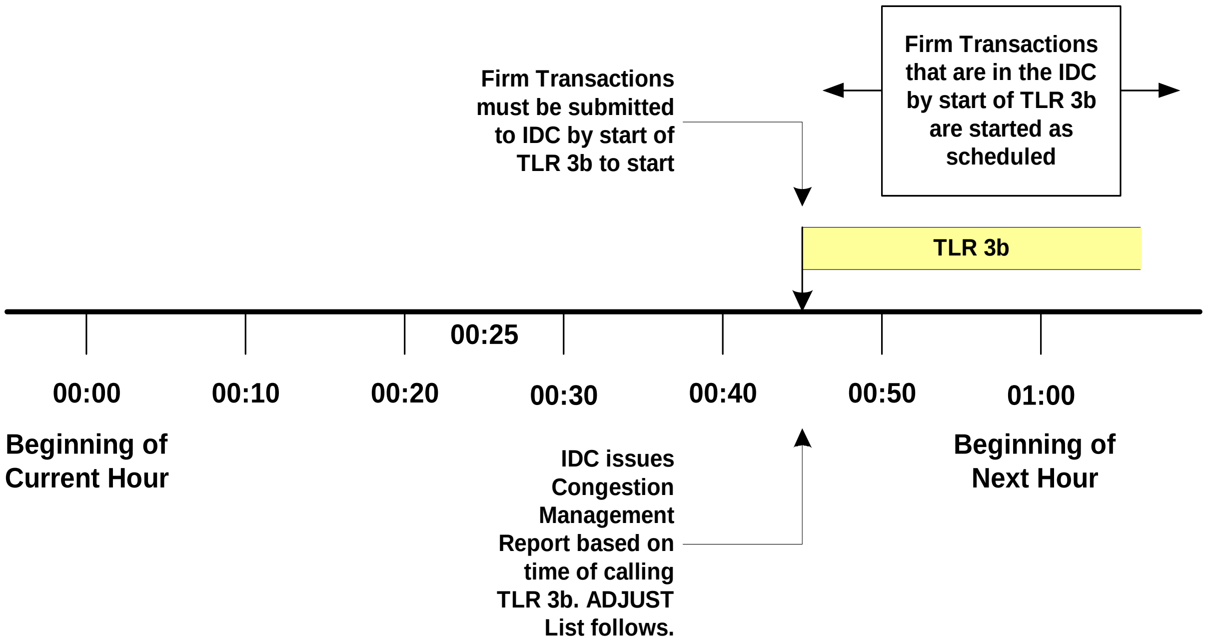
1. The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.
2. The IDC will issue an ADJUST List based upon the time the TLR 3b is called. The ADJUST List will include curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as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

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

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

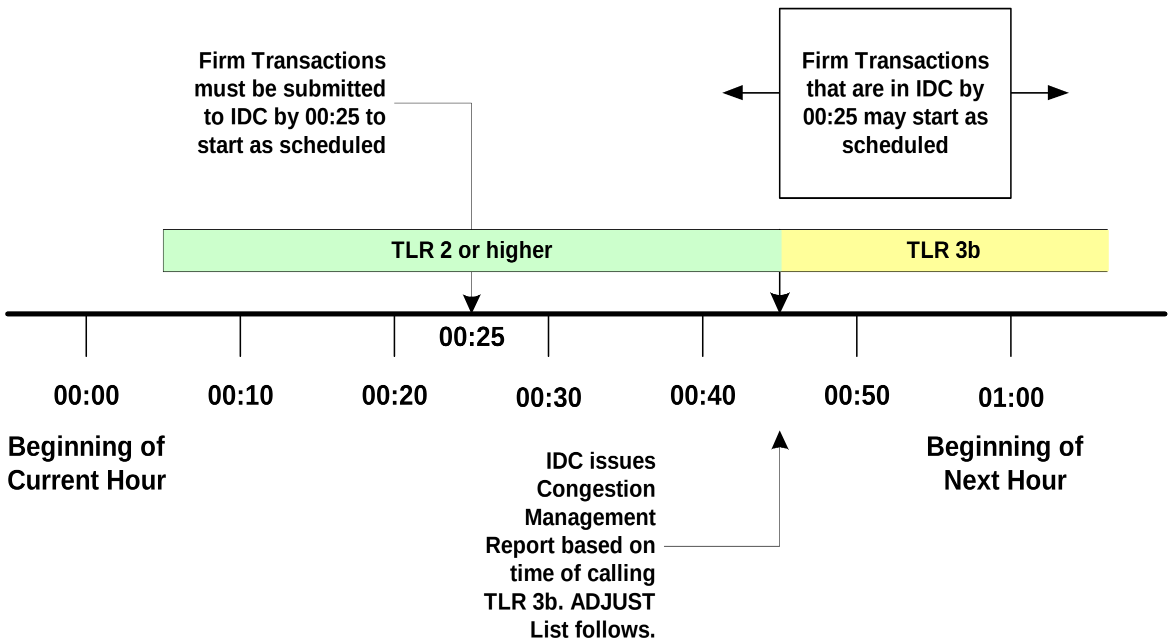
    b. Interchange Transactions using Non-firm Point-to-Point Transmission Service that were held may then be reallocated to start at 02:00.

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



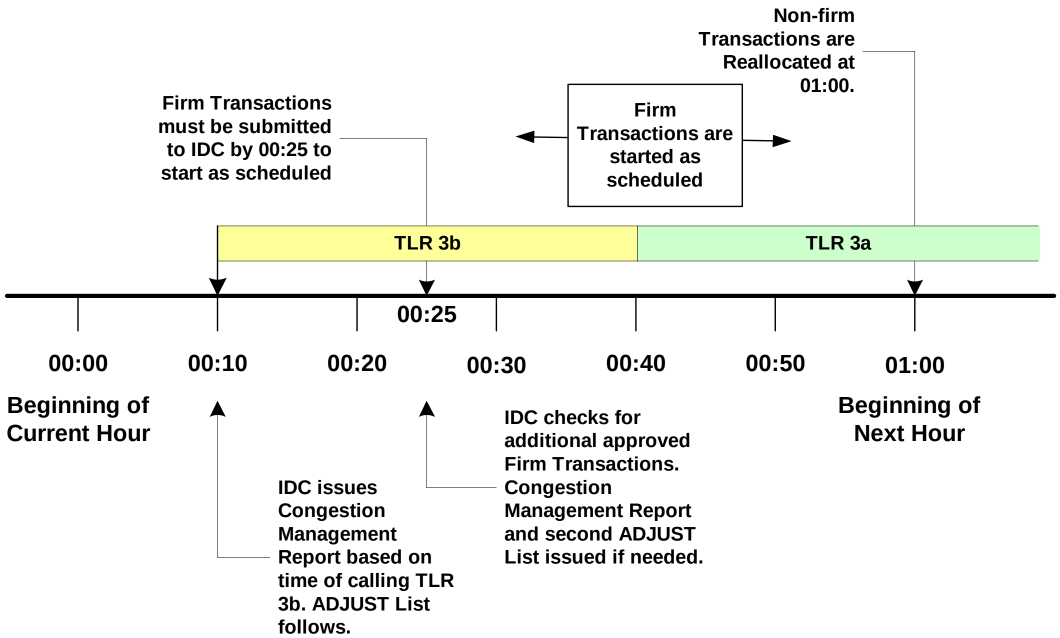
1. The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.
2. The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service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

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



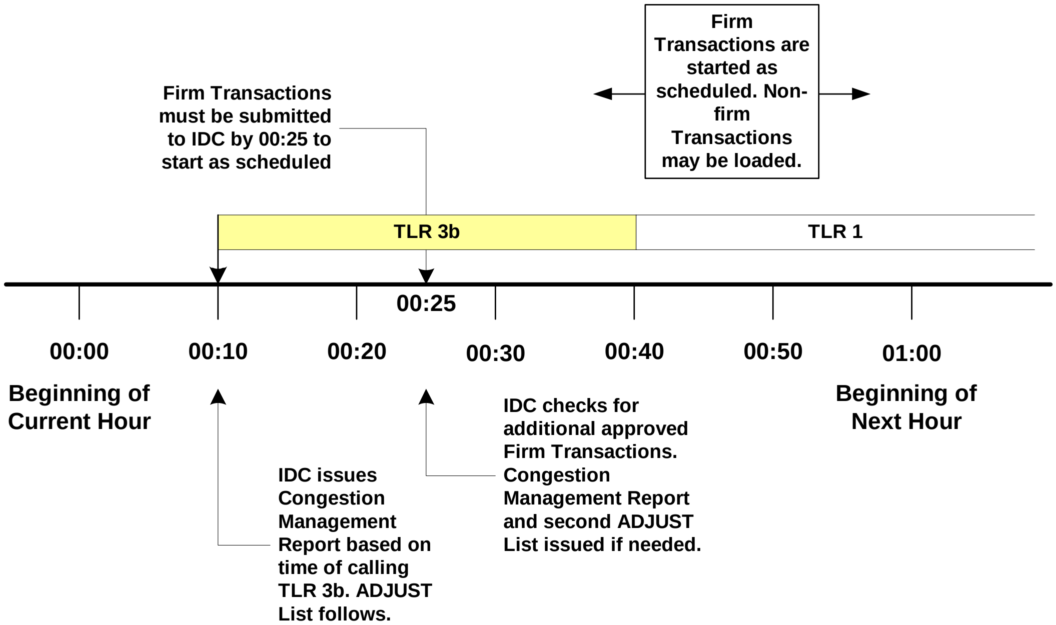
If a TLR 2 or higher has been issued and 3B is subsequently issued, then only those Interchange Transactions using Firm Point-to-Point Transmission Service that had been submitted to the IDC by 00:25 will be allowed to start as scheduled. All other Interchange Transactions are held.

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



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

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



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

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

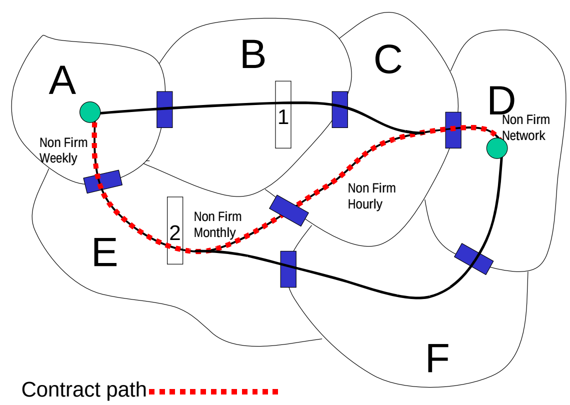
Examples

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

Scenario:

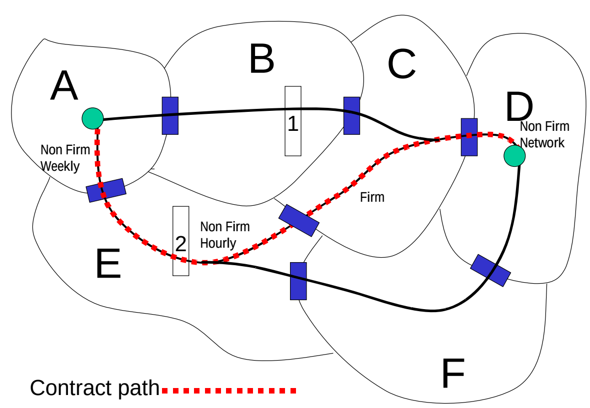
- Interchange Transaction arranged from system A to system D, and assumed to be at or above the Curtailment Threshold.
- Contract path is A-E-C-D (except as noted).
- Locations 1 and 2 denote Constraints.

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



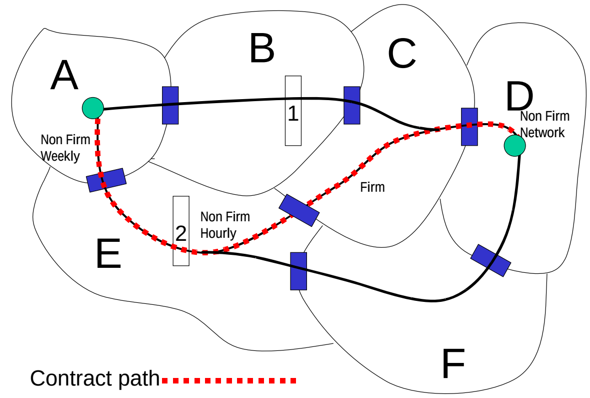
- E may call its Reliability Coordinator for TLR to relieve overload at Constraint #2.
- Interchange Transaction A-D may be curtailed by TLR action **as though it was being served by Non-firm Monthly Point-to-Point Transmission Service**, even though it was using Non-firm Hourly Point-to-Point Transmission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

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



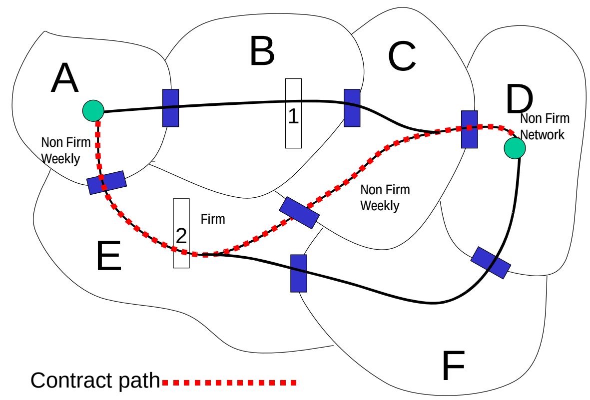
- Although C is providing Firm Service, the Constraint is not on C's system; therefore E is not obligated to treat the Interchange Transaction as though it was being served by Firm Point-to-Point Transmission Service.
- E may call its Reliability Coordinator for TLR to relieve overload at Constraint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

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



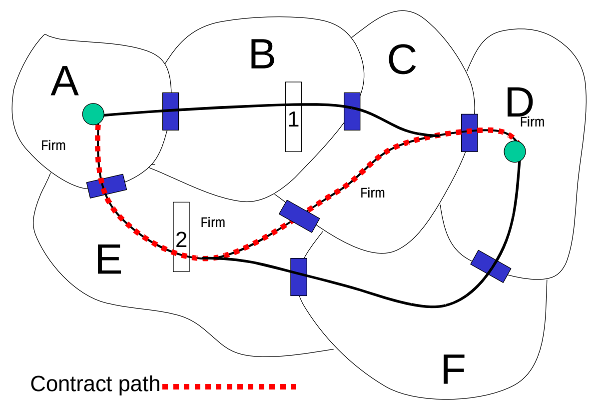
- B may call its Reliability Coordinator for TLR to relieve overload at Constraint #1.
- Interchange Transaction A-D may be curtailed by TLR action as though it was being served by Non-firm Hourly Transmission Service, even if it was using firm Transmission Service elsewhere on the path. When the constraint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

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



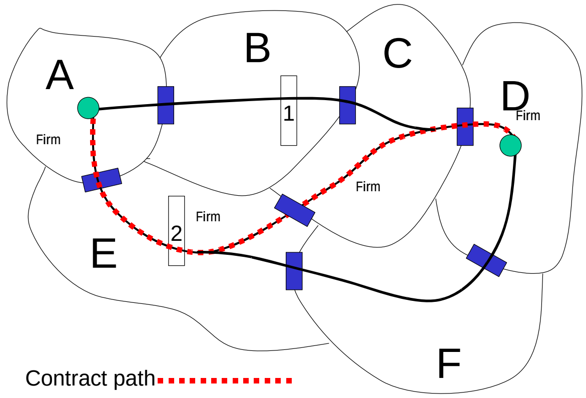
- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may then call its Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-firm Point-to-Point Transmission Service first.
- E is obligated to try to reconfigure transmission to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

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



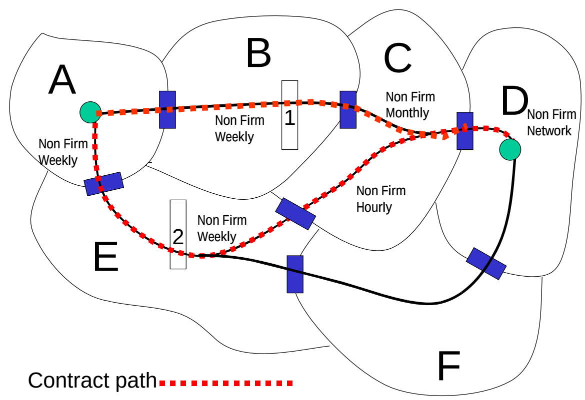
- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may call its Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-firm Point-to-Point Transmission Service first.
- E is obligated to curtail Interchange Transactions using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

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



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

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



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

A. Introduction

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

2. **Number:** EOP-005-1

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

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Effective Date:** One year after BOT adoption.

B. Requirements

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

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

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

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

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

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

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

R8. Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator's area.

R9. The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started and shall provide this documentation for review by the Regional Reliability Organization upon request. Such documentation may include Cranking Path diagrams.

R10. The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.

R10.1. The Transmission Operator shall perform this simulation or testing at least once every five years.

R11. Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.

R11.1. The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).

R11.2. The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.

R11.3. The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments as needed to facilitate the restoration. The affected Balancing Authorities shall make all attempts to maintain the adjusted Interchange Schedules, whether generation control is manual or automatic.

R11.4. The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.

R11.5. The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:

R11.5.1. Voltage, frequency, and phase angle permit.

R11.5.2. The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are considered.

R11.5.3. Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.

R11.5.4. Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.

C. Measures

M1. The Transmission Operator shall within 30 calendar days of a request, provide its Regional Reliability Organization with documentation of simulations or tests that demonstrate the blackstart units and Cranking Paths identified in the Transmission Operator's restoration plan can perform their intended functions as required in the regional restoration plan.

M2. The Transmission Operator shall within 30 calendar days of a request from its Regional Reliability Organization, make available documentation showing the number, size, and location of system blackstart generating units and the associated Cranking Paths for review at the Transmission Operator's location.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

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

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

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

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

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

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

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

1.4.5 The number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator's area

1.4.6 The Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started have been documented and this documentation is available for the Regional Reliability Organization's review.

1.4.7 The blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.

2. Levels of Non-Compliance

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

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

2.3. Level 3: Did not make available documentation showing the number, size, and location of system blackstart generating units and the associated Cranking Paths.

2.4. Level 4: There shall be a level four non-compliance if any of the following conditions exist:

2.4.1 Plan exists but does not address two or more of the requirements in Attachment 1 – EOP-005.

2.4.2 No restoration plan in place.

2.4.3 No simulation or test results as required in Requirement 10.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Attachment 1 – EOP-005

Elements for Consideration in Development of Restoration Plans

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

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

A. Introduction

1. **Title:** **Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures**

2. **Number:** MOD-013-1

3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. **Applicability:**

   4.1. Regional Reliability Organization.

5. **Effective Date:** Six months after BOT adoption.

B. Requirements

R1. The Regional Reliability Organization, in coordination with its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. Each set of Interconnection-wide dynamics data requirements shall include the following dynamics data requirements:

R1.1. Design data shall be provided for new or refurbished excitation systems (for synchronous generators and synchronous condensers) at least three months prior to the installation date.

R1.1.1. If design data is unavailable from the manufacturer 3 months prior to the installation date, estimated or typical manufacturer’s data, based on excitation systems of similar design and characteristics, shall be provided.

R1.2. Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment.

R1.2.1. Estimated or typical manufacturer’s dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.

R1.2.2. The Interconnection-wide requirements shall specify unit size thresholds for permitting:

- The use of non-detailed vs. detailed models,
- The netting of small generating units with bus load, and
- The combining of multiple generating units at one plant.

R1.3. Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, and static compensators.

R1.4. Dynamics data representing electrical Demand characteristics as a function of frequency and voltage.

R1.5. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard MOD-010 Requirement 1.

R2. The Regional Reliability Organization shall participate in the documentation of its Interconnection's data requirements and reporting procedures and, shall participate in the review of those data requirements and reporting procedures (at least every five years), and shall provide those data requirements and reporting procedures to Regional Reliability Organizations, NERC, and all users of the Interconnected systems on request (within five business days).

C. Measures

M1. The Regional Reliability Organizations within each Interconnection shall have documentation of their Interconnection's dynamics data requirements and reporting procedures and shall provide the documentation as specified in Requirement 2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Data requirements and reporting procedures: on request (five business days).

Periodic review of data requirements and reporting procedures: at least every five years.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Data requirements and reporting procedures for dynamics data were provided, but were incomplete in one of the five areas defined in R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Data requirements and reporting procedures provided were incomplete in two or more of the five areas defined in R1.

2.4. Level 4: Data requirements and reporting procedures for dynamics data were not provided, or the data requirements and reporting procedures provided were incomplete in three or more of the five areas defined in R1.

E. Regional Differences

None identified.

Version History

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

A. Introduction

1. **Title: Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management**

2. **Number:** MOD-016-1

3. **Purpose:** Ensure that accurate, actual Demand data is available to support assessments and validation of past events and databases. Forecast Demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, to assist in proper real-time operating, Load information related to controllable Demand-Side Management (DSM) programs is needed.

4. **Applicability:**

   4.1. Planning Authority.

   4.2. Regional Reliability Organization.

5. **Effective Date:** Six months after BOT adoption.

B. Requirements

R1. The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.

R1.1. The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021.

The data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.

R2. The Regional Reliability Organization shall distribute its documentation required in Requirement 1 and any changes to that documentation, to all Planning Authorities that work within its Region.

The Regional Reliability Organization shall make this distribution within 30 calendar days of approval.

The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area. The Planning Authority shall make this distribution within 30 calendar days of approval.

C. Measures

M1. The Planning Authority and Regional Reliability Organization's documentation for actual and forecast customer data shall contain all items identified in R1.

M2. The Regional Reliability Organization shall have evidence it provided its actual and forecast customer data reporting requirements as required in Requirement 2.

M3. The Planning Authority shall have evidence it provided its actual and forecast customer data and reporting requirements as required in Requirement 3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor for Planning Authority: Regional Reliability Organization.
Compliance Monitor for Regional Reliability Organization: NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

For the Regional Reliability Organization and Planning Authority: Current version of the documentation.

For the Compliance Monitor: Three years of audit information.

1.4. Additional Compliance Information

The Regional Reliability Organization and Planning Authority shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Documentation does not address completeness and double counting of customer data.

2.2. Level 2: Documentation did not address one of the three types of data required in R1 (Demand data, Net Energy for Load data, and controllable DSM data).

2.3. Level 3: No evidence documentation was distributed as required.

2.4. Level 4: Either the documentation did not address two of the three types of data required in R1 (Demand data, Net Energy for Load data, and controllable DSM data) or there was no documentation.

E. Regional Differences

None identified.

Version History

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

A. Introduction

1. **Title:** **Define and Document Disturbance Monitoring Equipment Requirements.**
2. **Number:** PRC-002-0
3. **Purpose:** To ensure that Disturbance monitoring equipment is installed in a uniform manner to facilitate development of models and analyses of events.
4. **Applicability:**
   4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Regional Reliability Organization shall develop comprehensive requirements for the installation of Disturbance monitoring equipment to ensure data is available to determine system performance and the causes of System Disturbances. The comprehensive requirements shall include all of the following:

R1.1. Type of data recording capability (e.g., sequence-of-event, Fault recording, dynamic Disturbance recording).

R1.2. Equipment characteristics including but not limited to:

R1.2.1. Recording duration requirements.

R1.2.2. Time synchronization requirements.

R1.2.3. Data format requirements.

R1.2.4. Event triggering requirements

R1.3. Monitoring, recording, and reporting capabilities of the equipment.

R1.3.1. Voltage.

R1.3.2. Current.

R1.3.3. Frequency.

R1.3.4. MW and/or MVAR, as appropriate.

R1.4. Data retention capabilities (e.g., length of time data is to be available for retrieval).

R1.5. Regional coverage requirements (e.g., by voltage, geographic area, electric area or subarea).

R1.6. Installation requirements:

R1.6.1. Substations.

R1.6.2. Transmission lines.

R1.6.3. Generators.

R1.7. Responsibility for maintenance and testing.

R1.8. Requirements for periodic (at least every five years) updating, review, and approval of the Regional requirements.

R2. The Regional Reliability Organization shall provide its requirements for the installation of Disturbance monitoring equipment to other Regional Reliability Organizations and NERC on request (30 calendar days).

C. Measures

M1. The Regional Reliability Organization's requirements for the installation of Disturbance monitoring equipment shall address all elements listed in Reliability Standard PRC-002-0_R1.

M2. The Regional Reliability Organization shall have evidence it provided its requirements for the installation of Disturbance monitoring equipment to other Regional Reliability Organizations and NERC on request (30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request by NERC (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's Disturbance monitoring requirements do not address one of the eight requirements contained in Reliability Standard PRC-002-0_R1.

2.2. Level 2: The Regional Reliability Organization's Disturbance monitoring requirements do not address two of the eight requirements contained in Reliability Standard PRC-002-0_R1.

2.3. Level 3: The Regional Reliability Organization's Disturbance monitoring requirements do not address three of the eight requirements contained in Reliability Standard PRC-002-0_R1.

2.4. Level 4: The Regional Reliability Organization's Disturbance monitoring requirements were not provided or do not address four or more of the eight requirements contained in Reliability Standard PRC-002-0_R1.

E. Regional Differences

1. None identified.

Version History

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

A. Introduction

1. **Title:** **Disturbance Monitoring Equipment Installation and Data Reporting**
2. **Number:** PRC-018-1
3. **Purpose:** Ensure that Disturbance Monitoring Equipment (DME) is installed and that Disturbance data is reported in accordance with regional requirements to facilitate analyses of events.
4. **Applicability**
   - **4.1.** Transmission Owner.
   - **4.2.** Generator Owner.
5. **Effective Dates:** Phased in over four years after BOT adoption:

   Requirements 1 and 2:

   – 50% compliant two years after initial issuance of regional requirements per RELIABILITY STANDARD PRC-002 Requirement 5.

   – 75% compliant three years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   – 100% compliant four years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   Requirements 3 through 6:

   – 100% compliant six months after BOT adoption for already installed DME.

   – 100% compliant six months after installation for DMEs installed to meet Regional Reliability Organization requirements per reliability standard PRC-002 Requirements 1, 2 and 3.

B. Requirements

R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:

R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)

R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar days..

R2. The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization’s installation requirements (reliability standard PRC-002 Requirements 1 through 3).

R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region’s installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):

R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).

R3.2. Make and model of equipment.

R3.3. Installation location.

R3.4. Operational status.

R3.5. Date last tested.

R3.6. Monitored elements, such as transmission circuit, bus section, etc.

R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc.

R3.8. Monitored electrical quantities, such as voltage, current, etc.

R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).

R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.

R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:

R6.1. Maintenance and testing intervals and their basis.

R6.2. Summary of maintenance and testing procedures.

C. Measures

M1. The Transmission Owner and Generator Owner shall each have evidence that DMEs it is required to have meet the functional requirements specified in Requirement 1 and are installed in accordance with its associated Regional Reliability Organization's requirements (R2).

M2. The Transmission Owner and Generator Owner shall each maintain the data listed in Requirements 3.1 through 3.8 for the DMEs installed to meet its Regional Reliability Organization's DME installation requirements.

M2.1 The Transmission Owner and Generator Owner shall each have evidence it provided this DME data to its Regional Reliability Organization within 30 calendar days of a request.

M3. The Transmission Owner and Generator Owner shall each have evidence it retained and provided recorded Disturbance data to entities in accordance with its associated Regional Reliability Organization's Disturbance data reporting requirements. (R4 R5)

M4. Each Transmission Owner and Generator Owner that is required to install DMEs to meet its Regional Reliability Organization's DME installation requirements, shall have an associated DME maintenance and testing program as defined in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each retain any Disturbance data provided to the Regional Reliability Organization (Requirement 4) for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if any of the following conditions is present:

2.1.1 DMEs that meet all the Regional Reliability Organization's installation requirements (in accordance with Requirement 2) were installed at 90% or more but not all of the required locations.

2.1.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with Requirement 4) was provided for 90% or more but not all of the required locations.

2.1.3 Data on required DMEs was incomplete (in accordance with R3)

2.1.4 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions is present:

2.2.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at 80% or more but less than 90% of the required locations.

2.2.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for 80% or more but less than 90% of the required locations.

2.2.3 Recorded Disturbance data was not provided to all required entities (in accordance with R4)

2.2.4 Archived data was not retained for three years (in accordance with Requirement 5).

2.2.5 Documentation of the DME maintenance and testing program provided was complete as required in R6, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions is present:

2.3.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at 70% or more but less than 80% of the required locations.

2.3.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for 70% or more but less than 80% of the required locations.

2.3.3 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. **Level 4:** There shall be a level four non-compliance if any one of the following conditions is present:

2.4.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at less than 70% of the required locations.

2.4.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for less than 70% of the required locations.

2.4.3 DMEs that meet all functional requirements (in accordance with R1) were not installed at all required locations.

2.4.4 Documentation of the DME maintenance and testing program was not provided, or no evidence that the testing program did occur within the identified intervals

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Normal Operations Planning**
2. **Number:** TOP-002-1
3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.
4. **Applicability**
   4.1. Balancing Authority.
   4.2. Transmission Operator.
   4.3. Generation Operator.
   4.4. Load Serving Entity.
   4.5. Transmission Service Provider.
5. **Effective Date:** Six months after effective date of VAR-001-1.

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

R14.1. Changes in real output capabilities.

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

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

A. Introduction

1. **Title:** **Voltage and Reactive Control**
2. **Number:** VAR-001-1
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Transmission Operators.
   - **4.2.** Purchasing-Selling Entities.
5. **Effective Date:** Six months after BOT adoption.

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.

R3.1. Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.

R3.2. For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

R5. Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.

R6. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.

R6.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: No evidence that exempt Generator Owners were notified of their exemption as specified under R3.2

2.2. Level 2: There shall be a level two non-compliance if either of the following conditions exists:

2.2.1 No evidence to show that directives were issued in accordance with R6.1.

2.2.2 No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with R11.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions exists:

2.3.1 Voltage or Reactive Power schedules were provided for some but not all generating units as required in R4.

2.4. Level 4: No evidence voltage or Reactive Power schedules were provided to Generator Operators as required in R4.

D. Regional Differences

None identified.

Version History

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

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**

2. **Number:** VAR-002-1

3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.

4. **Applicability**

   4.1. Generator Operator.

   4.2. Generator Owner.

5. **Effective Date:** Six months after effective date of VAR-001-1.

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator..

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

---

[1] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Generator Operator

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 One incident of failing to notify the Transmission Operator as identified in , R3.1, R3.2 or R5.1.

2.1.2 One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1,R3.2 or R5.1.

2.2.2 More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.3.2 More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 Failed to comply with the Transmission Operator's directives as identified in R2.

2.4.2 Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.4.3 Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. Levels of Non-Compliance for Generator Owner:

3.1.1 **Level One:** Not applicable.

3.1.2 **Level Two:** Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.

3.1.3 **Level Three:** No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage

3.1.4 **Level Four:** Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added “(R2)” to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006

The newly approved terms are included in the shaded table rows below.

Glossary of Terms Used in Reliability Standards

August 2, 2006

Term	Acronym	Definition
Adequacy		The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority		A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact		The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
Agreement		A contract or arrangement, either written or verbal and sometimes enforceable by law.
Altitude Correction Factor		A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.
Ancillary Service		Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)
Anti-Aliasing Filter		An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error	ACE	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.
Arranged Interchange		The state where the Interchange Authority has received the Interchange information (initial or revised).
Automatic Generation Control	AGC	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.

Term	Acronym	Definition
Available Transfer Capability	ATC	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area		The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Base Load		The minimum amount of electric power delivered or required over a given period at a constant rate.
Blackstart Capability Plan		A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Bulk Electric System		As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.
Burden		Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Capacity Benefit Margin	CBM	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

Term	Acronym	Definition
Capacity Emergency		A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading		The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
Clock Hour		The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration		Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor		The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Confirmed Interchange		The state where the Interchange Authority has verified the Arranged Interchange.
Congestion Management Report		A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Constrained Facility		A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contingency		The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Reserve		The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Contract Path		An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.
Control Performance Standard	CPS	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.

Term	Acronym	Definition
Corrective Action Plan		A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path		A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.
Critical Assets		Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.
Critical Cyber Assets		Cyber Assets essential to the reliable operation of Critical Assets.
Curtailment		A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Curtailment Threshold		The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Cyber Assets		Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Security Incident		Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.
Demand		1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management	DSM	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Direct Control Load Management	DCLM	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.
Dispersed Load by Substations		Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.

Term	Acronym	Definition
Distribution Factor	DF	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).
Distribution Provider		Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Disturbance		1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard	DCS	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.
Disturbance Monitoring Equipment	DME	Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders[1]: • Sequence of event recorders which record equipment response to the event • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays. • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions
Dynamic Interchange Schedule or Dynamic Schedule		A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.

[1] Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

Term	Acronym	Definition
Dynamic Transfer		The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.
Economic Dispatch		The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electrical Energy		The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Security Perimeter		The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Element		Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Emergency or BES Emergency		Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating		The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Energy Emergency		A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Equipment Rating		The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
Facility		A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

Term	Acronym	Definition
Facility Rating		The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault		An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk		The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand		That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service		The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover		An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate		A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.
Forced Outage		1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias		A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.
Frequency Bias Setting		A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Deviation		A change in Interconnection frequency.
Frequency Error		The difference between the actual and scheduled frequency. (F_A – F_S)
Frequency Regulation		The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.

Term	Acronym	Definition
Frequency Response		(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).
Generator Operator		The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner		Entity that owns and maintains generating units.
Generator Shift Factor	GSF	A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
Generator-to-Load Distribution Factor	GLDF	The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Host Balancing Authority		1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value		Data measured on a Clock Hour basis.
Implemented Interchange		The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
Inadvertent Interchange		The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. ($I_A - I_S$)
Independent Power Producer	IPP	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc.	IEEE	

Term	Acronym	Definition
Interchange Distribution Calculator	IDC	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.
Interchange		Energy transfers that cross Balancing Authority boundaries.
Interchange Authority		The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interchange Schedule		An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction		An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag		The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service		A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection		When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection Reliability Operating Limit	IROL	The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.
Intermediate Balancing Authority		A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities
Interruptible Load or Interruptible Demand		Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

Term	Acronym	Definition
Joint Control		Automatic Generation Control of jointly owned units by two or more Balancing Authorities.
Limiting Element		The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load		An end-use device or customer that receives power from the electric system.
Load Shift Factor	LSF	A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity		Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Misoperation		▪ Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. ▪ Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). ▪ Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.
Native Load		The end-use customers that the Load-Serving Entity is obligated to serve.
Net Actual Interchange		The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load		Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule		The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange		The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.

Term	Acronym	Definition
Network Integration Transmission Service		Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.
Non-Firm Transmission Service		Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve		1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Rating		The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Off-Peak		Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak		Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service	OASIS	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff	OATT	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Plan		A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Term	Acronym	Definition
Operating Procedure		A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process		A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve		That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve – Spinning		The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Reserve – Supplemental		The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Voltage		The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Overlap Regulation Service		A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.

Term	Acronym	Definition
Peak Demand		1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period		The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Physical Security Perimeter		The physical, completely enclosed (“six-wall”) border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Planning Authority		The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Point of Delivery	POD	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt	POR	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Point to Point Transmission Service	PTP	The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Pro Forma Tariff		Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.
Protection System		Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.
Pseudo-Tie		A telemetered reading or value that is updated in real time and used as a “virtual” tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
Purchasing-Selling Entity		The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.

Term	Acronym	Definition
Ramp Rate or Ramp		(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions		The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate
Rating		The operational limits of a transmission system element under a set of specified conditions.
Reactive Power		The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power		The portion of electricity that supplies energy to the load.
Reallocation		The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.
Real-time		Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Receiving Balancing Authority		The Balancing Authority importing the Interchange.
Regional Reliability Organization		1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.
Regional Reliability Plan		The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
Regulating Reserve		An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

Term	Acronym	Definition
Regulation Service		The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Coordinator		The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Coordinator Area		The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Area		The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Information System	RCIS	The system that Reliability Coordinators use to post messages and share operating information in real time.
Remedial Action Scheme	RAS	See "Special Protection System"
Reportable Disturbance		Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.
Reserve Sharing Group		A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.

Term	Acronym	Definition
Resource Planner		The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
Response Rate		The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Request for Interchange	RFI	A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.
Right-of-Way (ROW)		A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Scenario		Possible event.
Schedule		(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency		60.0 Hertz, except during a time correction.
Scheduling Entity		An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path		The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority		The Balancing Authority exporting the Interchange.
Sink Balancing Authority		The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority		The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)

Term	Acronym	Definition
Special Protection System (Remedial Action Scheme)		An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
Spinning Reserve		Unloaded generation that is synchronized and ready to serve additional demand.
Stability		The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
Stability Limit		The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Supervisory Control and Data Acquisition	SCADA	A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service		A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.
Surge		A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.
Sustained Outage		The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System		A combination of generation, transmission, and distribution components.

Term	Acronym	Definition
System Operating Limit		The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator		An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.
Telemetering		The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating		The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line		A circuit connecting two Balancing Authority Areas.
Tie Line Bias		A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error		The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction		An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.

Term	Acronym	Definition
TLR Log		Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.
Total Transfer Capability	TTC	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transaction		See Interchange Transaction.
Transfer Capability		The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not g*enerally equal to the transfer capability from "Area B" to "Area A."
Transfer Distribution Factor		See Distribution Factor.
Transmission		An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission Constraint		A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer		1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line		A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator		The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.

Term	Acronym	Definition
Transmission Owner		The entity that owns and maintains transmission facilities.
Transmission Planner		The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
Transmission Reliability Margin	TRM	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Service		Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider		The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
Vegetation		All plant material, growing or not, living or dead.
Vegetation Inspection		The systematic examination of a transmission corridor to document vegetation conditions.
Wide Area		The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.

Exhibit A-1 -- Redline Version of Revised Reliability Standards

A. Introduction

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

2. **Number:** BAL-006-~~0~~1

3. **Purpose:**

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

4. **Applicability:**

   4.1. Balancing Authorities.

5. **Effective Date**~~———April~~**:** May 1, ~~2005~~2006
   This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.

B. Requirements

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

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

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

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

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

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

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

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

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

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

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

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

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

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

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

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

2. Levels of Non Compliance

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

E. Regional Differences

1. MISO RTO Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004. This regional difference will be extended to include SPP effective May 1, 2006.

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	April 6, 2006	Added following to “Effective Date:” This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata

A. Introduction

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

2. **Number:** EOP-005-~~0~~1

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

4. **Applicability**

   ~~4.2.~~4.1. Transmission Operators.

   ~~4.3.~~4.2. Balancing Authorities.

5. **Effective Date:** ~~April 1, 2005~~ One year after BOT adoption.

B. Requirements

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

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

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

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

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

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

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

R8. Each Transmission Operator shall ~~ensure~~verify that the number, size, availability, and location of ~~black start capability within its area~~system blackstart generating units are sufficient to meet ~~the needs of the~~ Regional Reliability Organization restoration plan requirements for the Transmission Operator's area.

R9. The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started and shall provide this documentation for review by the Regional Reliability Organization upon request. Such documentation may include Cranking Path diagrams.

R10. The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.

R10.1. The Transmission Operator shall perform this simulation or testing at least once every five years.

R11. Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.

R11.1. The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).

R11.2. The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators ~~on~~on line, or load shedding.

R11.3. The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments as needed to facilitate the restoration. The affected Balancing Authorities shall make all attempts to maintain the adjusted Interchange Schedules, whether generation control is manual or automatic.

R11.4. The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.

R11.5. The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:

R11.5.1. Voltage, frequency, and phase angle permit.

R11.5.2. The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are considered.

R11.5.3. Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.

R11.5.4. Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.

C. Measures

~~Not specified.~~

M1. The Transmission Operator shall within 30 calendar days of a request, provide its Regional Reliability Organization with documentation of simulations or tests that demonstrate the blackstart units and Cranking Paths identified in the Transmission Operator's restoration plan can perform their intended functions as required in the regional restoration plan.

M2. The Transmission Operator shall within 30 calendar days of a request from its Regional Reliability Organization, make available documentation showing the number, size, and location of system blackstart generating units and the associated Cranking Paths for review at the Transmission Operator's location.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

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

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

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

~~1.1.1~~1.4.1 The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.

~~1.1.2~~1.4.2 A set of procedures for annual review for simulating and, where practical, actual testing and verification of the restoration plan resources and procedures.

~~1.1.3~~1.4.3 Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.

~~1.1.4~~1.4.4 Any significant changes to the restoration plan must be reported to the Regional Reliability Organization.

~~**1.2. Compliance Monitoring Period**~~The number, size, availability, and ~~**Reset Timeframe**~~

~~One calendar year.~~

~~**1.3. Data Retention**~~

1.4.5 ~~The Transmission Operator must have its plan to reestablish its electric~~location of system ~~available for a review by the~~ blackstart generating units are sufficient to meet Regional Reliability Organization ~~at all times.~~restoration plan requirements for the Transmission Operator's area

~~**1.4. Additional Compliance Information**~~

1.4.6 ~~None~~The Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started have been documented and this documentation is available for the Regional Reliability Organization's review.

1.4.7 The blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.

2. **Levels of Non-Compliance**

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

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

2.3. Level 3: ~~N/A~~Did not make available documentation showing the number, size, and location of system blackstart generating units and the associated Cranking Paths.

2.4. Level 4: There shall be a level four non-compliance if any of the following conditions exist:

2.4.1 Plan exists but does not address two or more of the requirements in Attachment 1- – EOP-005~~-0, or there is no~~.

~~2.4.~~2.4.2 No restoration plan in place.

2.4.3 No simulation or test results as required in Requirement 10.

E. Regional Differences

None identified.

Version History

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

Attachment 1~~-~~ – EOP-005~~-0~~

Elements for Consideration in Development of Restoration Plans

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

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

A. Introduction

1. **Title:** **Interchange ~~Transaction~~ Tagging Information**

2. **Number:** INT-001-~~0~~1

3. **Purpose:**

   To ensure that Interchange ~~Transactions, certain Interchange Schedules, and intra-Balancing Authority Area transfers using Point-~~information is submitted to ~~-Point Transmission Service are Tagged in adequate time to allow~~ the ~~transactions to be assessed for~~NERC-identified reliability ~~impacts by the affected Reliability Coordinators, Transmission Service Providers, and Balancing Authorities, and to allow adequate time for implementation.~~analysis service.

4. **Applicability:**

   4.1. Purchase-Selling Entities.

   4.2. Balancing Authorities.

5. **Effective Date:** ~~April~~January 1, ~~2005~~2007

B. Requirements

~~**R1.**~~ The Load-~~serving~~Serving, Purchasing-Selling Entity shall ~~be responsible for ensuring Tags are~~ensure that Arranged Interchange is submitted ~~for:~~

R1. ~~All~~to the Interchange ~~Transactions that are between Balancing~~ Authority ~~Areas~~for:

~~**R1.2.** All transfers that are entirely within a Balancing Authority Area using Point-to-Point Transmission Service (including all grandfathered and "non-Order 888" Point-to-Point Transmission Service).~~

R1.1. All Dynamic Schedules at the expected average MW profile for each hour.

R2. The Sink Balancing Authority shall ~~be responsible for ensuring a Tag~~ ensure that Arranged Interchange is ~~provided~~submitted to the Interchange Authority:

R2.1. If a Purchasing-Selling Entity is not involved in the ~~Transaction~~Interchange, such as delivery from a jointly owned generator.

~~**R2.2.** To replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements. If the duration of the Emergency Transaction to replace the generation loss is less than 60 minutes, then the Transaction shall be exempt from Tagging.~~

~~**R2.3.**~~ ~~All~~For each bilateral ~~inadvertent interchange~~ Inadvertent Interchange payback.

~~**R3.** The Purchasing Selling Entity responsible for submitting the Tag shall submit all Tags to the Sink Balancing Authority according to timing tables in Attachment 1-INT-001-0.~~

~~**R4.** The Balancing Authority or Purchasing-Selling Entity responsible for submitting the Tag shall include the reliability data listed in Attachment 2-INT-001-0 in the Tag.~~

~~**R5.** Each Purchasing-Selling Entity with title to an Interchange Transaction shall have, or shall arrange to have, personnel directly and immediately available for notification of Interchange Transaction changes. These personnel shall be available from the time that the title to the Interchange Transaction is acquired until the Interchange Transaction has been completed.~~

~~C. Measures~~

~~**M1.**~~**R2.2.** ~~A Balancing Authority shall provide documentation to show all scheduled interchanges between Balancing Authority Areas were Tagged.~~

C. Compliance

Not Specified.

D. Regional Differences

1. WECC Tagging Dynamic Schedules and Inadvertent Payback Waiver effective on November 21, 2002.
2. MISO Energy Flow Information Waiver effective on July 16, 2003.

Version History

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

~~Attachment 1-INT-001-0 — Tag Submission and Response Timetables for New Transactions~~

~~Eastern Interconnection – New Transactions~~

~~The table below represents the Tag submission and assessment deadlines within the Eastern Interconnection. These are default requirements; some regulatory or provincially-approved provider practices may have requirements that are more stringent. Under these instances, the more restrictive criteria shall be adhered to. The table describes the various minimum submission and assessment timing requirements.~~

~~Table 1: Eastern Interconnection – Timing Requirements~~

~~Transaction Duration~~	~~PSE Submit Deadline*~~	~~Actual Tag Submission Time~~	~~Provider Assessment Time~~	~~Time to Start of Transaction~~
~~Less than 24 Hours~~	~~20 Minutes prior to start~~	~~≤1 Hour prior to start~~	~~≤ 10 Minutes from Tag receipt~~	~~≥ 10 Min~~
		~~>1 to <4 hours prior to start~~	~~≤20 Minutes from Tag receipt~~	~~≥ 40 Min~~
		~~≥ 4 Hours prior to start~~	~~≤ 2 Hours from Tag receipt~~	~~≥ 2 Hours~~
~~24 Hours or longer~~	~~4 Hours prior to start~~	~~Any~~	~~≤ 2 Hours from Tag receipt~~	~~≥ 2 Hours~~
~~*Start time references are for start of the Transaction not the start of the Ramp.~~				

~~Tag submission timing requirements are based on the duration of the Transaction. Tags representing Transactions that run for less that one day (24 hours) must be submitted at least 20 minutes prior to the start of the Transaction (excluding Ramp time). Tags representing Transactions running for one day or more (24 hours or more) must be submitted at least four hours prior to the start. Tags submitted that meet these requirements shall be considered "on-time" and may be granted conditional approval. Tags submitted that do not meet these requirements shall be considered "late," and consequently will be denied if not explicitly approved by all parties.~~

~~Tag assessment timing requirements are based on the submission time of the Tag, as well as the duration. Hourly Tags submitted one hour or less prior to start must be evaluated in ten minutes. Hourly Tags submitted more than one hour but less than four hours prior to start must be evaluated in 20 minutes. Tags of a duration less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. Tags of duration 24 hours or more must be evaluated in two hours.~~

~~1) Eastern Interconnection — Reallocation During a Transmission Loading Relief (TLR) Event~~

~~During a NERC TLR event, Transactions may be submitted to replace existing Transactions with a lower transmission priority. The new Transaction Tag must be received no later than 35 minutes prior to the top of the hour to allow time for Reliability Coordinator to assess the impact of reallocation.~~

~~**Western Interconnection – New Transactions**~~

~~The table below represents the Tag submission and assessment deadlines within the Western Interconnection. These are default requirements. The tables describe the various minimum submission and assessment timing requirements.~~

~~**Table 2: Western Interconnection – Timing Requirements**~~

~~**Transaction Start/Submittal Time**~~	~~**Late Status Deadline**~~	~~**Actual Tag Submission Time***~~	~~**Provider Assessment Time**~~	~~**Approval/ Denial Notes**~~	~~**Time to Start of Transaction***~~
~~Start 00:00 next day or beyond when submitted prior to 18:00 of the current day~~	~~15:00 day prior to start~~	~~Any~~	~~3 hours~~	~~Passive approval if submitted before deadline, else passive denial. Deferred denial~~	~~≥ 6 Hours~~
~~Start 00:00 next day and submitted between 18:00 and 23:59:59 on day prior to start – OR – start within current day~~		~~≥ 4 Hours prior to start~~	~~2 Hours from Tag receipt~~	~~Passive approval Deferred denial~~	~~≥ 2 Hours~~
		~~<4 Hours to ≥1 Hour prior to start~~	~~20 minutes from Tag receipt~~	~~Passive approval Deferred denial~~	~~≥ 40 Min~~
		~~<1 hour to ≥30 minutes prior to start~~	~~10 minutes from Tag receipt~~	~~Passive approval Deferred denial~~	~~≥ 20 Min~~
		~~<30 minutes to ≥20 minutes prior to start~~	~~10 minutes from Tag receipt~~	~~Passive approval Deferred denial~~	~~≥ 10 Min~~
	~~20 minutes prior to start~~	~~<20 minutes prior to start~~	~~5 minutes from Tag receipt~~	~~Passive denial. Deferred denial~~	~~Submission time minus maximum time of 5 minutes~~
~~Notes/Clarification:~~ ~~All clock times are in Pacific Prevailing Time (PPT).~~ ~~Tags falling under the criteria in the first row are deemed pre-schedule Tags.~~ ~~Tags falling under the criteria in the remaining rows are deemed real-time Tags.~~ ~~Pre-schedule Tags submitted between 15:00 and 18:00 will be assigned LATE composite status.~~ ~~Real-time Tags submitted after 20 minutes prior to the start of the Transaction will be assigned LATE composite status.~~ ~~*Start-time references are for start of the Transaction, not the start of the Ramp.~~					

~~Tag submission timing requirements are based on the type and duration of the Transaction. Tags representing Transactions that run for less that one day (24 hours) within the current day must be submitted at least 20 minutes prior to the start of the Transaction (excluding Ramp time). Tags representing Transactions that are pre-scheduled to start the next day must be submitted by 1500 PST the~~

~~day prior to the day the Transaction is to start. Tags submitted that meet these requirements shall be considered "on-time" and may be granted conditional approval. Tags submitted that do not meet these requirements shall be considered "late," and consequently will be denied if not explicitly approved by all parties.~~

~~Tag assessment timing requirements are based on the submission time of the Tag, as well as the duration. Hourly Tags submitted one hour or less prior to start must be evaluated in ten minutes. Hourly Tags submitted more than one hour but less than four hours prior to start must be evaluated in 20 minutes. Tags of a duration less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. Tags submitted for pre-scheduled service starting the next day or a future day must be evaluated in three hours.~~

~~**Attachment 2-INT-001-0 — Required Tag Data**~~

~~The following is the reliability information necessary to assess a Transaction:~~

1. ~~Physical path — the description of physically scheduling parties, always containing a generation segment, at least one transmission segment, and a Load segment.~~
2. ~~Generation — the physical characteristics of the energy source.~~
3. ~~Resource service point — the physical point at which the energy is being generated. This may vary in granularity, depending on local practices.~~
4. ~~Energy profile — energy to be produced by the generator for each time segment of the Transaction.~~
5. ~~Transmission — the physical characteristics of a wheel (import, export, or through).~~
6. ~~Transmission Service Provider — the identity of the Transmission Service Provider that is wheeling the energy.~~
7. ~~Point of receipt — valid point of receipt for scheduled transmission reservation.~~
8. ~~Point of delivery — valid point of delivery for scheduled transmission reservation.~~
9. ~~Scheduling entity(ies) — entities that are physically scheduling interchange on behalf of the Transmission Service Provider in order to provide wheeling services. Typically this is the Balancing Authority providing a service for the Transmission Service Provider, but several Balancing Authorities may be supporting a regional transmission service.~~
10. ~~Loss provision — the manner in which losses are accounted when they are not scheduled as in-kind megawatt distributions through the original transaction or through a separately Tagged transaction.~~
11. ~~POR and POD profiles — schedule of energy flow imported at the Point of Receipt and Exported at the Point of Delivery.~~
12. ~~Transmission reservation number — reference to a particular transmission reservation being used to provide transmission capacity to support the transaction being described.~~
13. ~~Transmission reservation profile — information describing the transmission reservation commitment.~~
14. ~~Transmission product — the firmness of service associated with the transmission reservation being used.~~
15. ~~Load — the physical characteristics of the energy sink.~~
16. ~~Resource service point (sink) — the physical point at which the energy is being consumed. This may vary in granularity, dependent on local practices.~~
17. ~~Energy profile — energy to be consumed by the Load for this Transaction.~~
18. ~~Contact information of person representing the Purchasing-Selling Entity responsible for the Tag.~~

~~The following information is required to modify a Transaction:~~

19. ~~The Transaction being curtailed or reloaded.~~
20. ~~All necessary profile changes to set the maximum flow allowed for the transaction during the appropriate hours.~~
21. ~~A contact person that initiated the curtailment or reload.~~

A. Introduction

1. **Title:** **Interchange Transaction Implementation**

2. **Number:** INT-003-~~0~~1

3. **Purpose:**

To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations. ~~To ensure Balancing Authorities incorporate all confirmed Schedules into their ACE equations.~~

4. **Applicability**

4.1. Balancing Authorities.

5. **Effective Date:** ~~April~~January 1, ~~2005~~2007

B. Requirements

R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on~~:~~ Interchange as received from the Interchange Authority, including:

R1.1.1. Interchange Schedule start and end time.

R1.1.2. Energy profile.

~~**R1.1.3.** Ramp start time and duration (Balancing Authorities shall use the Ramp duration established for their Interconnection unless they agree to an alternative Ramp duration.) Default Ramps durations are as follows:~~

- ~~Default Ramp duration for the Eastern Interconnection shall be 10 minutes equally across the Interchange Schedule start and end times.~~
- ~~Default Ramp duration for the Western Interconnection shall be 20 minutes equally across the Interchange Schedule start and end times.~~
- ~~Ramp durations for Interchange Schedules implemented for compliance with NERC's Disturbance Control Standard (recovery from a disturbance condition) and Interchange Transaction curtailment in response to line loading relief procedures may be shorter than the above defaults, but must be identical for the Sending Balancing Authority and Receiving Balancing Authority.~~

R1.2. If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie.

~~**R1.3.** Balancing Authorities that implement Interchange Schedules that cross an Interconnection boundary shall use the same start time and Ramp durations.~~

~~**R2.** Balancing Authorities shall implement Interchange Schedules only with Adjacent Balancing Authorities.~~

~~**R3.** Balancing Authorities shall begin and end Interchange Schedules at a time agreed to by the Source Balancing Authority, Sink Balancing Authority, and Intermediate Balancing Authorities.~~

~~**R4.** The Sink Balancing Authority shall be responsible for initiating implementation of each Interchange Transaction as tagged. Upon receiving composite approval from the Sink~~

~~Balancing Authority, each Balancing Authority on the scheduling path shall enter confirmed Schedules into its Automatic Generation Control ACE equation.~~

~~**R5.** Balancing Authorities shall operate such that Interchange Schedules do not knowingly cause any other systems to violate established operating criteria.~~

~~**R6.** Balancing Authorities shall operate such that the maximum Net Interchange Schedule between any two Balancing Authorities does not exceed the lesser of:~~

~~**R6.1.** The total capacity of both the owned and arranged-for transmission facilities in service for any Transmission Service Provider along the path, or~~

~~**R6.2.** The established network Total Transfer Capability between Balancing Authorities, which considers other transmission facilities available to them under specific arrangements, and the overall physical constraints of the transmission network.~~

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

1. MISO Scheduling Agent Waiver dated November 21, 2002.
2. MISO Enhanced Scheduling Agent Waiver dated July 16, 2003.
3. MISO Energy Flow Information Waiver dated July 16, 2003.

Version History

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

A. Introduction

1. **Title:** **Dynamic Interchange Transaction Modifications**

2. **Number:** INT-004-~~0~~1

3. **Purpose:** To ~~allow modifications to Interchange Transactions to address potential or actual System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations or other reliability conditions. To~~ ensure Dynamic Transfers are adequately tagged to be able to determine their reliability impacts.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Reliability Coordinators

   4.3. Transmission Operators

   4.4. Purchasing-Selling Entities

5. **Effective Date:** ~~April~~January 1, ~~2005~~2007

B. Requirements

~~**R1.** If a Reliability Coordinator, Transmission Operator, or Source or Sink Balancing Authority, due to a reliability event, needs to modify an Interchange Transaction that is in progress or scheduled to be started, the entity shall, within 60 minutes of the start of the emergency Transaction, modify the Interchange Transaction tag, and shall communicate the modification to the Sink Balancing Authority. Reliability events may include:~~

~~**R1.1.** Transmission Loading Relief procedure curtailment — Eastern Interconnection.~~

~~**R1.2.** Interconnection, regional, or local overload relief or congestion management procedures.~~

~~**R1.3.** SOL or IROL potential or actual limit violation.~~

~~**R1.4.** Loss of generation.~~

~~**R1.5.** Loss of Load.~~

~~**R2.** A Generator Operator or Load Serving Entity may request the Host Balancing Authority to modify an Interchange Transaction due to loss of generation or Load.~~

~~**R2.1.** When a loss of generation necessitates curtailing Interchange Transactions, the Source Balancing Authority shall coordinate the modifications to the appropriate tags.~~

~~**R2.2.** When a loss of Load necessitates curtailing Interchange Transactions, the Sink Balancing Authority shall coordinate the modifications to the appropriate tags.~~

~~**R3.** Upon receipt of modification to an Interchange Transaction as described in Requirement R1, the Sink Balancing Authority (Source Balancing Authority in the case of a loss of generation) shall communicate the modified information about the Interchange Transaction, including its composite approval status, to all Balancing Authorities and Transmission Service Providers on the Transaction path and the Purchasing-Selling Entity responsible for the Transaction.~~

R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.

R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs:

R2.1. The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±10%.

R2.2. The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±25 megawatt-hours.

R2.3. A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.

C. Measures

M1. The Sink Balancing Authority shall provide evidence that the responsible Purchasing-Selling Entity revised a tag when the deviation exceeded the criteria in INT-004 Requirement ~~R5~~2.

D. Compliance

1. Compliance Monitoring Process

Periodic tag audit as prescribed by NERC. For the requested time period, the Sink Balancing Authority shall provide the instances when Dynamic Schedule deviation exceeded the criteria in ~~Requirement 5~~INT-004 R2 and shall provide evidence that the responsible Purchasing-Selling Entity submitted a revised tag.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset ~~Timeframe~~Time Frame

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

1.3. Data Retention

Three months.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Not specified.

2.2. Level 2: Not specified.

2.3. Level 3: Not specified.

2.4. Level 4: Not specified.

E. Regional Differences

1. WECC Tagging Dynamic Schedules and Inadvertent Payback Waiver dated November 21, 2002.

Version History

Version	Date	Action	Change Tracking

0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

~~Attachment 1-INT-004-0~~

~~Interchange Transaction Modifications~~

~~Curtailments, reloads, market-initiated modifications, and other Transaction modifications that affect energy profiles must be received by and evaluated within certain times. The following tables describe the submission and evaluation requirements for such changes.~~

~~Modification requests received by the deadlines specified below shall be considered “on time,” and are eligible for passive approval. Modification requests received past the deadlines shall be considered “late,” and are considered denied unless explicitly approved by all parties.~~

~~Table 1: Eastern Interconnection — Modifications~~

~~Modification Type~~	**~~Requestor Submission Deadline***~~**	**~~Actual Submission Time***~~**	**~~Evaluation Time~~**
~~Reliability (Curtailments or Reloads)~~	~~20 minutes prior to modification start**~~	~~Less than 30 minutes to start~~	~~10 minutes~~
		~~30 minutes or more prior to start~~	~~15 minutes~~
~~Market — Committed transmission reservation(s) Reductions~~	~~N/A~~	~~N/A~~	~~N/A~~
~~Market — Committed transmission reservation(s) Increases, Energy Reductions, Energy Increases*~~	~~20 minutes prior to modification start**~~	~~Less than 30 minutes to start~~	~~10 minutes~~
		~~30 minutes or more prior to start~~	~~15 minutes~~
~~***Start time references are for start of the Transaction not the start of the Ramp.~~			

~~Table 2: Western Interconnection — Modifications~~

~~Modification Type~~	**~~Requestor Submission Deadline***~~**	**~~Actual Submission Time***~~**	**~~Evaluation Time~~**
~~Reliability (Curtailments or Reloads)~~	~~25 minutes prior to modification start**~~	~~Less than 30 minutes to start~~	~~10 minutes~~
		~~30 minutes or more prior to start~~	~~15 minutes~~
~~Market — Committed transmission reservation(s) Reductions~~	~~N/A~~	~~N/A~~	~~N/A~~
~~Market — Committed transmission reservation(s)~~	~~25 minutes prior to modification start**~~	~~Less than 30 minutes to start~~	~~10 minutes~~

~~Increases, Energy Reductions, Energy Increases*~~		~~30 minutes or more prior to start~~	~~15 minutes~~
~~***Start time references are for start of the Transaction not the start of the Ramp.~~			

~~*See Special Exception for Cancellations below.~~
~~**If received after deadline, requires active approval or will be passively denied~~

~~Special Exception for Cancellations~~

~~A cancellation is defined as setting both committed transmission reservation(s) and energy flow to zero for the duration of the Transaction prior to the start of a Transaction but following that Transaction's approval. In the event that a Purchasing-Selling Entity submitting the tag elects to cancel a Transaction, the following timelines should be utilized:~~

~~Table 3: Special Exception for Cancellations Submission and Evaluation Timing~~

~~Region~~	~~Submission Deadline*~~	~~Evaluation Time~~
~~Eastern Interconnection~~	~~15 minutes prior to transaction start~~	~~If received by deadline, no evaluation required. Request is automatically approved.~~
		~~If not received by deadline, request is not eligible for special exception for cancellations, and must be processed normally.~~
~~Western Interconnection~~	~~20 minutes prior to transaction start~~	~~If received by deadline, no evaluation required. Request is automatically approved.~~
		~~If not by deadline, request is not eligible for special exception for cancellations, and must be processed normally.~~
~~*Start time references are for start of the Transaction not the start of the Ramp.~~		

A. Introduction

1. Title: Reliability Coordination — Transmission Loading Relief

2. **Number:** IRO-006-~~1~~3

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. **Proposed Effective Date:** ~~August 8, 2005~~

   E.2 effective upon BOT adoption.

   Changes to TLR 3b and 4 for IRO-006-2 to be announced.

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~~Time Frame**

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

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

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

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

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

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

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

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

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

   Section 5 of Attachment 1-IRO-006-1 requires that the "Per Generator Method without Counter Flow" methodology be utilized to calculate the portion of parallel flows on any Constrained Facility due to Network Integration (NI) transmission service and service to Native Load (NL) of each balancing authority.

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

   The Market Flow Calculation differs from the Per Generator Method in the following ways:

   - The contribution from all market area generators will be taken into account.
   - In the Per Generator Method, only generators having a GLDF greater than 5% are included in the calculation. Additionally, generators are included only when the sum of the maximum generating capacity at a bus is greater than 20 MW. The market flow calculations will use all positively impacting flows down to 0% with no threshold. Counter flows will not be included in the market flow calculation.

- The contribution of all market area generators is based on the present output level of each individual unit.
- The contribution of the market area load is based on the present demand at each individual bus.

By expanding on the Per Generator Method, the market flow calculation evolves into a methodology very similar to the "Per Generator Method" method, while providing increased Interchange Distribution Calculator (IDC) granularity. Counter flows are also calculated and tracked in order to account for and recognize that the either the positive market flows may be reduced or counter flows may be increased to provide appropriate relief on a flowgate.

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

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

Appendix B "Transaction Curtailment Formula" details the formula used to apply a weighted impact to each non-firm tagged Interchange Transaction (Priorities 1 thru 6) for the purposes of Curtailment by the IDC. For the purpose of Curtailment, the non-firm market flow impacts (Priorities 2 and 6) submitted to the IDC by SPP should be curtailed pro-rata as is done for Interchange Transaction using firm transmission service. This is because several of the values needed to assign a weighted impact using the process listed in Appendix B will not be available:

- Distribution Factor (no tag to calculate this value from)
- Impact on Interface value (cannot be calculated without Distribution Factor)
- Impact Weighting Factor (cannot be calculated without Distribution Factor)
- Weighted Maximum Interface Reduction (cannot be calculated without Distribution Factor)
- Interface Reduction (cannot be calculated without Distribution Factor)
- Transaction Reduction (cannot be calculated without Distribution Factor)

While the non-firm market flow impacts submitted to the IDC are to be curtailed pro rata, the impacting non-firm tagged Interchange Transactions could still use the existing processes to assign the weighted impact value.

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

Under the header "IDC Calculations and Reporting" in Section E2 of Appendix E to Attachment 1-IRO-006-1, the following requirement exists: "In a TLR Level 3a the Interchange Transactions using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status. Solely for the purpose of identifying which Interchange Transactions to be loaded under a TLR 3a, various MW levels of an Interchange Transaction may be in different sub-priorities. The sub-priorities are shown in the following table:

Priority	Purpose	Explanation and Conditions
S1	To allow a flowing Interchange Transaction to maintain or reduce its current MW amount in accordance with its energy profile.	The MW amount is the lowest between currently flowing MW amount and the next-hour schedule. The currently flowing MW amount is determined by the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.
S2	To allow a flowing Interchange Transaction that has been curtailed or halted by TLR to reload to the *lesser* of its current-hour MW amount or next-hour schedule in accordance with its energy profile.	The Interchange Transaction MW amount used is determined through the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.
S3	To allow a flowing Transaction to increase from its current-hour schedule to its next-hour schedule in accordance with its energy profile.	The MW amounts used in this sub-priority is determined by the e-tag ENERGY PROFILE table. If the calculated amount is negative, zero is used instead.
S4	To allow a Transaction that had never started and was submitted to the Tag Authority after the TLR (level 2 or higher) has been declared 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.

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

These market flow impacts for current hour and next hour will be separated into their appropriate priorities and provided to the IDC by SPP. The market flows will then be represented and made available for curtailment under the appropriate TLR Levels.

Even though these market flow impacts (separated into appropriate priorities) will not be represented by conventional “tags,” the impacts and their desired levels will still be provided to the IDC for current hour and next hour. Therefore, for the purposes of reallocation, a sub-priority (S1 thru S4) should be assigned to these market flow impacts by the NERC IDC as follows, using comparable logic as would be used if the impacts were in fact tagged transactions.

Priority	Purpose	Explanation and Conditions
S1	To allow existing market flow to	The currently flowing MW amount is

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

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~~3

Transmission Loading Relief Procedure — Eastern Interconnection

Purpose

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

Applicability

This standard only applies to the Eastern Interconnection.

1. Transmission Loading Relief (TLR) Procedure

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Impacts of questionable IDC results may include:

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

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

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

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

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

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

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

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

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

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

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

2. Transmission Loading Relief (TLR) Levels

Introduction

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

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

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

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

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

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

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

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

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

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

2.2.3. TLR Level 2 is a transient state, which requires a quick decision to proceed to higher TLR Levels (3 and above) to allow Interchange Transactions to be implemented according to their transmission reservation priority. The time for being in TLR Level 2 should be no more than 30 minutes, with the understanding that there may be circumstances where this time may be exceeded. If the time in TLR Level 2 exceeds 30 minutes, the Reliability Coordinator shall document this action on the TLR Log.

2.3. TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service

2.3.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3a:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.
- The Transmission Provider has previously approved a higher priority Point-to-Point Transmission Service reservation over which a Transmission Customer wishes to begin an Interchange Transaction.

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

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

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

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

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

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

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

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

2.4. TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation

2.4.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3b**:**

- One or more transmission facilities are operating above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.

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

2.4.2. **Curtailment procedures to mitigate an SOL or IROL.** The Reliability Coordinator shall curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold as specified in Section 3, "Interchange Transaction Curtailment Order~~.~~**"** in the current hour to mitigate an SOL or IROL as well as reallocating, in accordance with Section 6 of this document, to a determined flow for the top of the next hour.

The Reliability Coordinator shall allow Interchange Transactions using Firm Point-to-Point Transmission Service to start if they are submitted to the IDC within specific time limits as explained in Section 7 "Interchange Transaction Curtailments during TLR Level 3b."

2.5. TLR Level 4 — Reconfigure Transmission

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

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

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

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

2.6. **TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service**

2.6.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 5a**:**

- The transmission system is secure.
- One or more transmission facilities are at their SOL or IROL.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- The Transmission Provider has been requested to begin an Interchange Transaction using previously arranged Firm Transmission Service that would result in a SOL or IROL violation.
- No further transmission reconfiguration is possible or effective.

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

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

2.6.2.2. **Step 2 —** The Reliability Coordinator shall calculate the percent of the overload on the Constrained Facility caused by both Firm Point-to-Point Transmission Service (at or above the Curtailment Threshold) and the

Transmission Provider's Network Integration Transmission Service and Native Load, as required by the Transmission Provider's filed tariff. This is described in Section 5, "Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service."

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

2.7. TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation

2.7.1. The Reliability Coordinator shall use following circumstances to establish the need for entering TLR Level 5b**:**

- One or more Transmission Facilities are operating above their SOL or IROL, or
- Such operation is imminent, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- No further transmission reconfiguration is possible or effective.

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

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

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

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

2.8. TLR Level 6 — Emergency Procedures

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

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

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

2.9. TLR Level 0 — TLR concluded

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

3. Interchange Transaction Curtailment Order for use in TLR Procedures

3.1. Priority of Interchange Transactions

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

Transmission Service Priorities

Priority 0. Next-hour Market Service — NX*

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

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

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

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

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

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

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

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

3.2. Curtailment of Interchange Transactions Using Non-firm Transmission Service

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

3.2.1.1. TLR Level 3a. Enable Interchange Transactions using a higher Transmission reservation priority to be implemented, or

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

3.3. Curtailment of Interchange Transactions Using Firm Transmission Service

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

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

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

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

Introduction

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

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

4.1. Constraints ON the Contract Path

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

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

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

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

4.2. Constraints OFF the Contract Path

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

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

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

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

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

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

Introduction

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

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

5.1. Requirements

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

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

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

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

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

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

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

5.2. Calculation Method

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

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

Introduction

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

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

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

6.1. Requirements

The basic requirements for Transaction Reallocation are as follows:

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

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

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

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

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

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

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

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

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

6.2. Communication and Timing Requirements

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

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

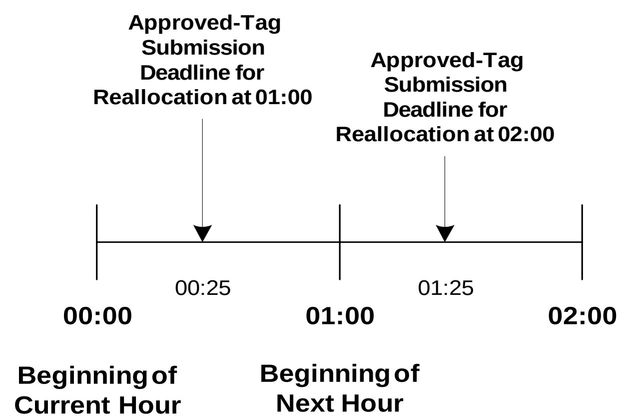


Figure 1 - Timeline showing Approved-tag Submission Deadline for Reallocation

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

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

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

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

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

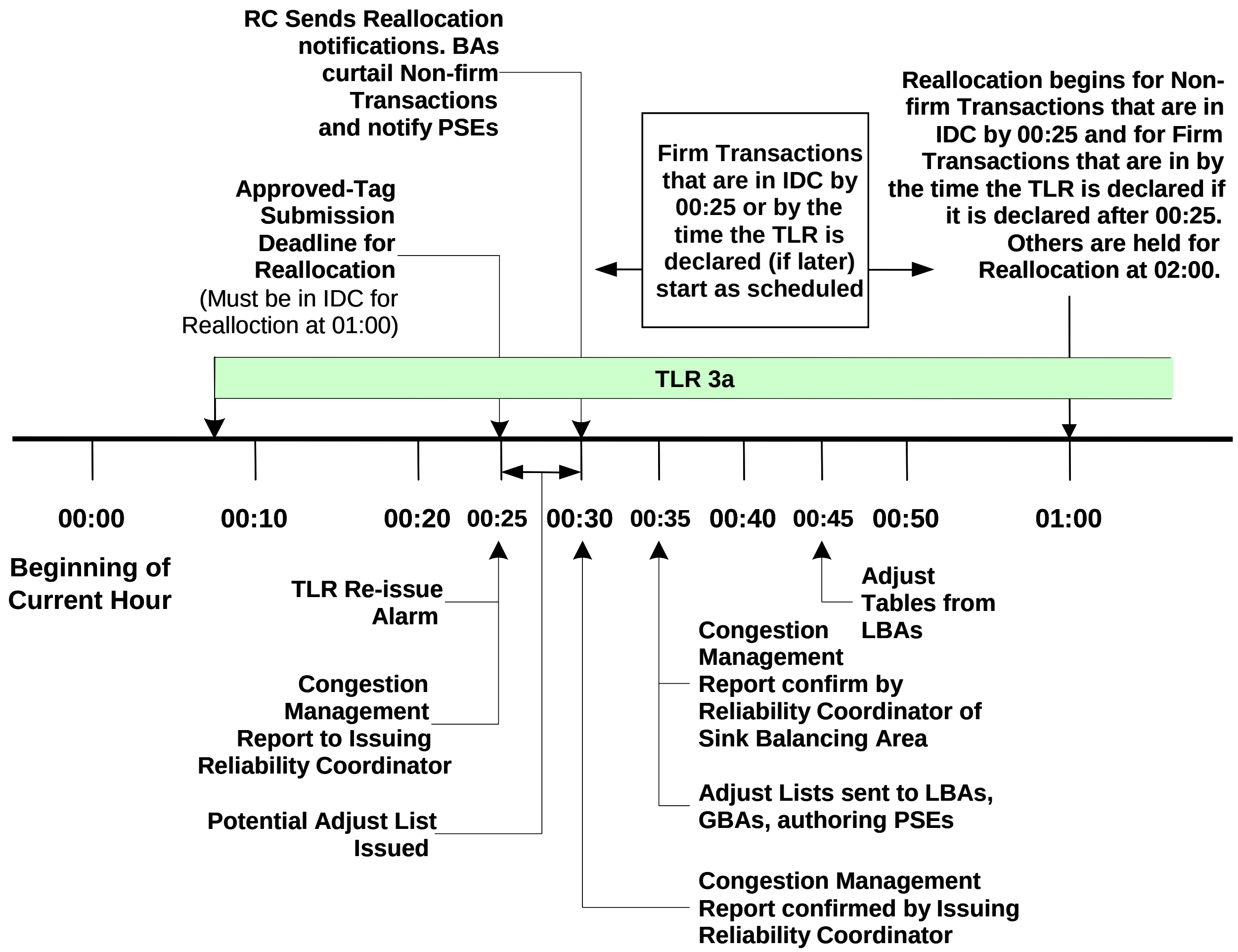


Figure 2 — Reallocation Timing for TLR 3a Called at 00:08

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

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

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

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

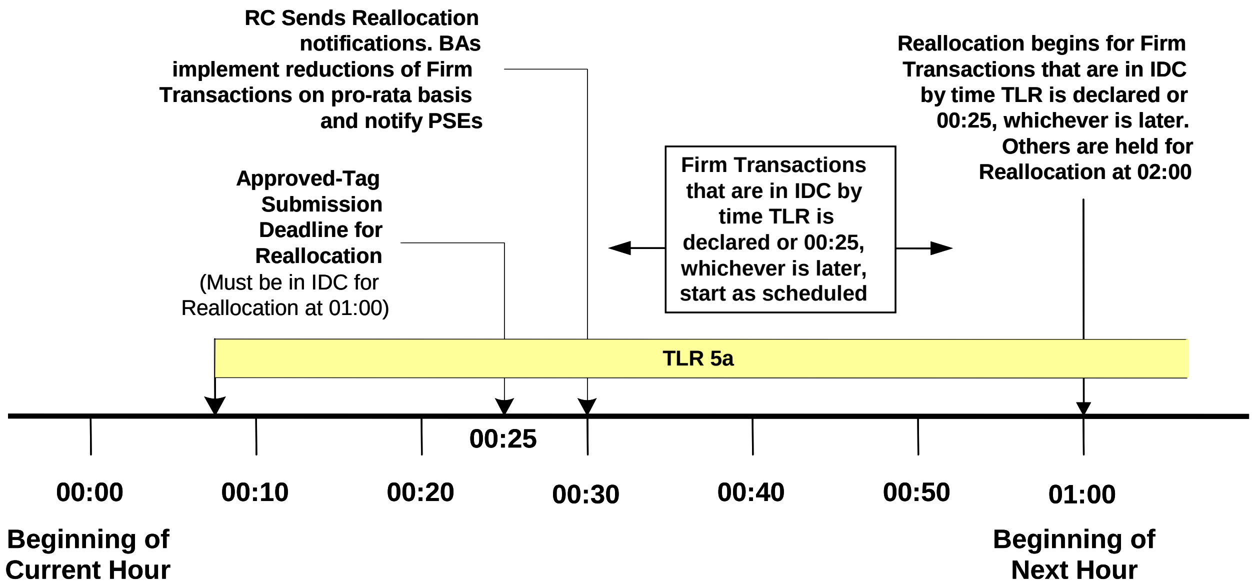


Figure 3 — Reallocation timing for TLR 5a called at 00:08.

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

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

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

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

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

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

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

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

Discussion: A Reliability Coordinator calls a TLR 2 or 3a whenever it deems necessary to indicate that a transmission facility is approaching its SOL or IROL. It is envisioned, though not required, that a TLR 2 or 3a is preceded by a period of a TLR 1 declaration, hence Transmission Customers should normally have advance notice of a potential constraint. For example, a TLR 3a initiated during the period 01:00 to 01:25 would allow the Purchasing-Selling Entity to submit a Tag for entry into the IDC by the Approved-Tag Submission Deadline for Reallocation at 02:00. See Figure 4. However, the preferred time period to declare a TLR 3a or 5a would be between 00:40 (when tags for Next Hour Market have been submitted) and 01:15. This will allow the Transmission Customers a range of 15 to 35 minutes to prepare and submit tags. (Note: In this situation, the Reliability Coordinator would need to reissue the TLR 3a at 01:00.)

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

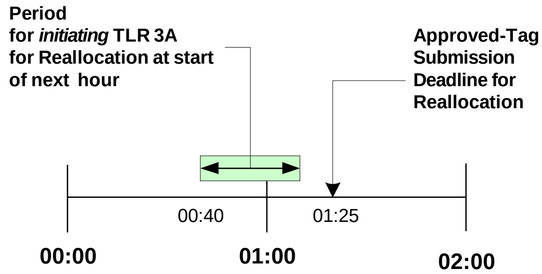


Figure 4. "Ideal" time for issuing TLR 3a for Reallocation at 02:00.

7. Interchange Transaction Curtailments During TLR Level 3b

Introduction

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

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

Requirements

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

7.2. The Reliability Coordinator shall consider only those Interchange Transactions at or above the Curtailment Threshold for curtailment~~,~~ or holding~~, or halting~~.

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

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

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

7.4. The Reliability Coordinator shall ~~not reallocate~~Reallocate Interchange Transactions using Non-firm Point-to-Point Transmission Service in accordance with Section 6 of this document for the next hour to maintain the desired flow using Reallocation in accordance with the following timing specification ~~during a TLR 3b.~~:

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

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

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

~~7.6.~~7.4.3. Transactions must be in the IDC by the Approved-tag Submission Deadline for Reallocation (see Requirement 6.2).

~~7.7.~~7.5. The Reliability Coordinator shall allow Interchange Transactions using Firm Point-to-Point Transmission Service to start as explained in Appendix F, “Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.”

~~7.8.~~7.6. The Reliability Coordinator shall progress to TLR Level 5b as necessary if there is still insufficient transmission capacity for Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled after all Interchange Transactions using Non-firm Point-to-Point Transmission Service have been curtailed.

~~7.9.~~7.7. The IDC shall issue ADJUST Lists to the Generation and Load Balancing Authority Areas and the Purchasing-Selling Entity who submitted the tag. The ADJUST List will include:

~~7.9.1.~~7.7.1. 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.~~7.7.2. Interchange Transactions using Firm Point-to-Point Transmission Service that were entered after ~~00~~XX:25 or issuance of TLR 3b (see Case 3 in Appendix F).

~~7.10.~~7.8. The Sink Balancing Authority shall send the ADJUST Lists back to the IDC as soon as possible to ensure the most accurate calculations for actions subsequent to the TLR 3b being called.

~~7.11.~~7.9. 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. due to the inherent next hour Reallocation that takes place for the top of the next hour in the TLR Level 3b.~~.~~

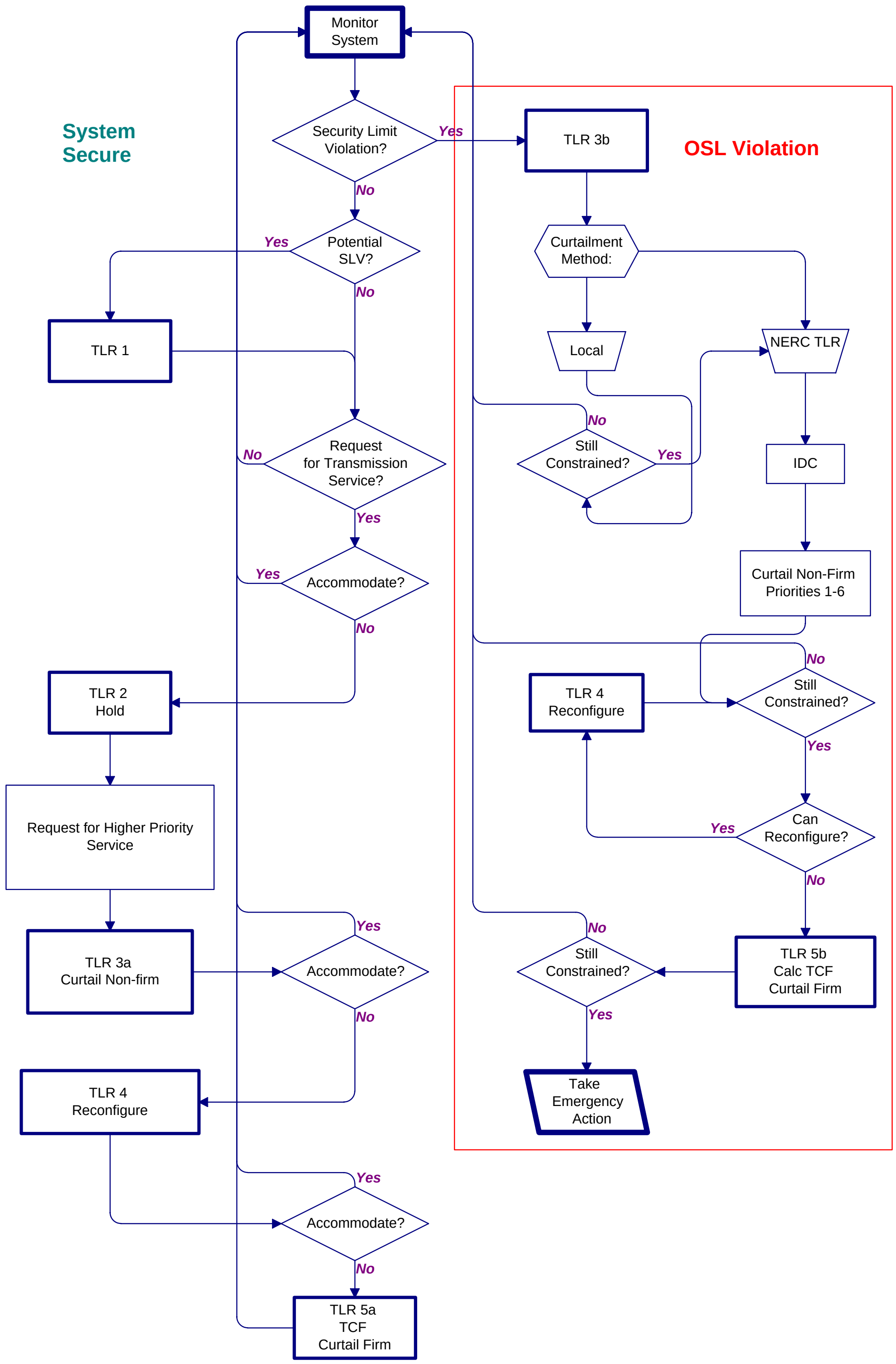
~~**7.10.1.**If the TLR Level 3a is called before the hour 01, then a Reallocation shall be computed for the start of that hour.~~

~~**7.10.2.**Transactions must be in the IDC by the Approved-tag Submission Deadline for Reallocation (see Requirement 6.2).~~

Appendices for Transmission Loading Relief Standard

Appendix A. Transaction Management and Curtailment Process

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



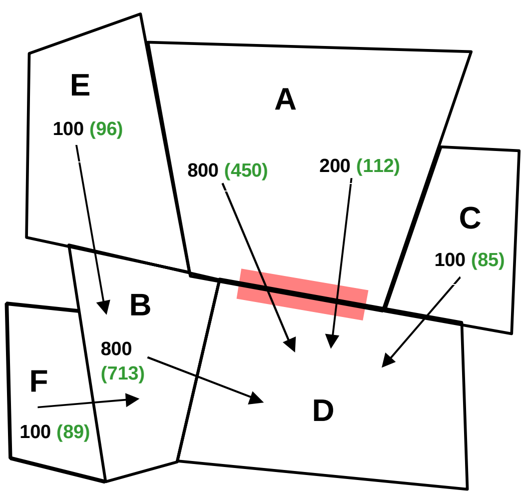
Appendix B. Transaction Curtailment Formula

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 Transmission Service

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

Example of Results of Calculation Method

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

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

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

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

Appendix E. How the IDC Handles Reallocation

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

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

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

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

Information posted from IDC to NERC TLR website.

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

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

3. Lowest priority of Interchange Transactions (marginal "bucket") to be Reloaded/Reallocated next-hour on each TLR Constrained Facility will be posted on NERC TLR website. This will provide an indication to the market of priority of Interchange Transactions that may be Reloaded/Reallocated the following hours.

IDC Logic, IDC Report, and Timing

1. The Reliability Coordinator will run the IDC the Reloading/Reallocation report at approximately 00:26. The IDC will prompt the Reliability Coordinator to enter a maximum loading value. The IDC will alarm if the Reliability Coordinator does not enter this value and issue a report by 00:30 or change from TLR 3a Level. The Report will be distributed to Balancing Authorities and Transmission Operators at 00:30. This process repeats every hour as long as the approved tag submission deadline for Reallocation is in effect (or until the TLR level is reduced to 1 or 0).

2. For Interchange Transactions in the restricted directions, tags must be submitted to the IDC by the approved tag submission deadline for Reallocation to be considered for Reallocation next-hour. The time stamp by the Tag Authority is regarded the official tag submission time.

3. Tags submitted to IDC after the approved tag submission deadline for Reallocation will not be allowed to start or increase but will be considered for Reallocation the next hour.

4. Interchange Transactions in restricted directions that are not indicated as "PROCEED" on the Reload/Reallocation Report will not be permitted to start or increase next hour.

Reloading/Reallocation Transaction Status

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

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

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

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

Reallocation/Reloading Priorities

1. Interchange Transaction candidates are ranked for loading and curtailment by priority as per Section 4, "Principles for Mitigating Constraints On and Off the Contract Path." This is called the "Constrained Path Method," or CPM. (secondary, hourly, daily, … firm etc). Interchange Transactions are curtailed and loaded pro-rata within priority level per TLR algorithm.

2. Reloading/Reallocation of Interchange Transactions are prioritized first by priority per CPM. E-Tags must be submitted to the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is scheduled to start or increase to be considered for Reallocation.

3. During Reloading/Reallocation, Interchange Transactions using lower priority Transmission Service will be curtailed pro-rata to allow higher priority transactions to reload, increase, or start. Equal priority Interchange Transactions will not reload, start, or increase by pro-rata Curtailment of other equal priority Interchange Transactions.

4. Reloading of Interchange Transactions using Non-firm Transmission Service with CURTAILED Status will take precedence over starting or increasing of Interchange Transactions using Non-firm Transmission Service of the same priority with PENDING Statuses.

5. Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled under TLR 3a as long as their E-Tag was received by the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is due to start or increase, regardless of whether the E-tag was submitted to the Tag Authority prior to TLR 2 or higher being declared or not. If this is the initial issuance of the TLR 3a, Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled as long as their E-Tag was received by the IDC by the time the TLR is declared.

Total Flow Value on a Constrained Facility for Next Hour

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

- Present constrained facility loading, present level of Interchange Transactions, and Balancing Authorities NNative Load responsibility (TLR Level 5a) impacting the Constrained Facility,

- SOLs or IROLs, known interchange impacts and Balancing Authority NNative Load responsibility (TLR Level 5a) on the Constrained Facility the next hour, and

- Interchange Transactions scheduled to begin the next hour.

2. The Reliability Coordinator will enter a maximum loading value for the constrained facility into the IDC as part of issuing the Reloading/Reallocation report.

3. The Reliability Coordinator is allowed to call for TLR 3a or 5a when approaching a SOL or IROL to allow maximum transactional flow next hour, and to manage flows without violating transmission limits.

4. The simultaneous curtailment and Reallocation for a Constrained Facility is allowed. This reduces the flow over the Constrained Facility while allowing Interchange Transactions using higher priority Transmission Service to start or increase the next hour. This may be used to accommodate change in flow next-hour due to changes other than Point-to-Point Interchange Transactions while respecting the priorities of Interchange Transactions flowing and scheduled to flow the next hour. The intent is to reduce the need for using TLR 3b, which prevents new Interchange Transactions from starting or increasing the next hour.

5. The Reliability Coordinator must allow Interchange Transactions to be reloaded as soon as possible. Reloading must be in an orderly fashion to prevent a SOL or IROL violation from (re)occurring and requiring holding or curtailments in the restricted direction.

E2. Timing Requirements

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

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

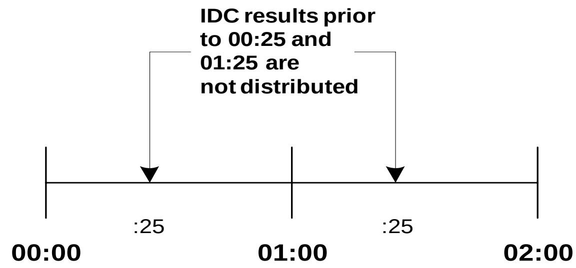


Figure 5 - IDC report may be run prior to 00:25, but results are not distributed.

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

Re-Issuing of a TLR Level 2 or Higher

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

IDC Assistance with Next Hour Point-to-Point Transactions

In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour for a TLR level 3a or 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour. In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour during a TLR level 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour as well as Balancing Authority with flows due to service to Network Customers and Native Load. The Reliability Coordinator will then be requested to provide the total incremental or decremental MW amount of flow through the Constrained Facility that can be allowed for the next hour. The value entered by the Reliability Coordinator and the

IDC-calculated amounts will be used by the IDC to identify the relief/reloading amounts (delta incremental flow value) on the constrained facility. The IDC will determine the Transactions to be reloaded, reallocated, or curtailed to make room for the Transactions using higher priority Transmission Service. The following examples show the calculation performed by IDC to identify the "delta incremental flow:"

Example 1

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

Example 2

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

Example 3

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

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

IDC Calculations and Reporting

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

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

2. In a TLR Level 3a the Interchange Transactions using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status. Solely for the purpose of identifying which Interchange Transactions to be loaded under a TLR 3a, various MW levels of an Interchange Transaction may be in different sub-priorities. The sub-priorities are shown in the following table:

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

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

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

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

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

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

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

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

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

Tag Reloading for TLR Levels 1 and 0

When a TLR Level 1 or 0 is issued, the Constrained Facility is no longer under SOL or IROL violation and all Interchange Transactions are allowed to flow. In order to provide the Reliability Coordinators with a view of the Interchange Transactions that were halted or curtailed on previous TLR actions (level 2 or higher) and are now available for reloading, the IDC provides such information in the TLR report.

New Tag Alarming

Those Interchange Transactions that are at or above the Curtailment Threshold and are *not* candidates for Reallocation because the tags for those Transactions were not submitted by the approved tag submission deadline for Reallocation will be flagged as HOLD and must not be permitted to start or increase during the next hour. To alert Reliability Coordinators of those Transactions required to be held, the IDC will generate a report (for viewing within the IDC only) at various times. The report will include a list of all HOLD Transactions. In order not to overwhelm the Reliability Coordinator with alarms, only those who issued the TLR and those whose Transactions sink within their Reliability Area will be alarmed. An alarm will be issued for a given tag only once and will be issued for all TLR levels for which halting new Transactions is required: TLR Level 2, 3a, 3b, 5a and 5b.

Tag Adjustment

The Interchange Transactions with statuses of HOLD, CURTAILED or PROCEED must be adjusted by a Tag Authority or Tag Approval entity. Without the tag adjustments, the IDC will assume that Interchange Transactions were not curtailed/held and are flowing at their specified schedule amounts.

1. Interchange Transactions marked as CURTAILED should be adjusted to a cap equal to, or at the request of the originating PSE, less than the reallocated amount (shown as the MW CAP on the IDC report). This amount may be zero if the Transaction is fully curtailed.
2. Interchange Transaction marked as PROCEED should be adjusted to reload (NULL or to its MW level in accordance with its Energy Profile in the adjusted MW in the E-Tag) if the Interchange Transaction has been previously adjusted; otherwise, if the Interchange Transaction is flowing in full, the Tag Authority need not issue an adjust.
3. Interchange Transactions marked as HOLD should be adjusted to 0 MW.

Special Tag Status

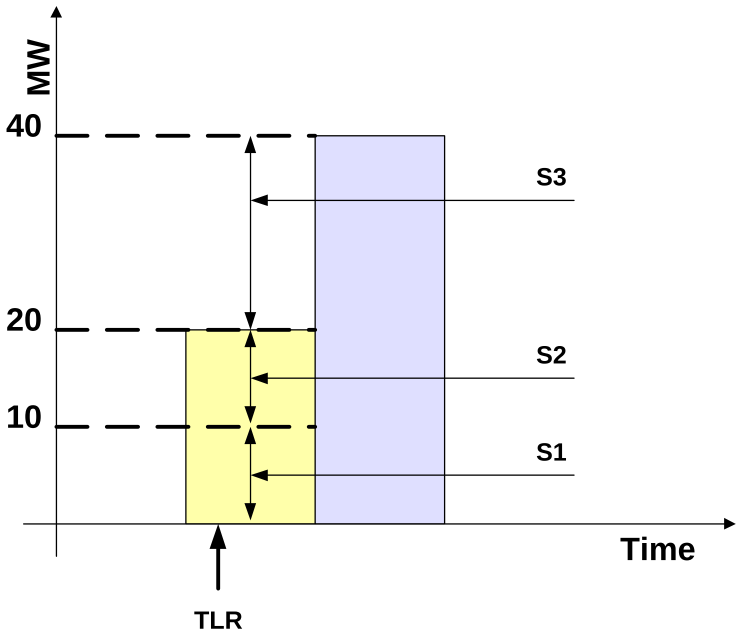
There are cases in which a tag may be marked with a composite state of ATTN_REQD to indicate that tag Authority/Approval failed to communicate or there is an inconsistency between the validation software of different tag Authority/Approval entities. In this situation, the tag is no longer subject to passive approval and its status change to IMPLEMENT may take longer than 10 minutes. Under these circumstances, the IDC may have a tag that is issued prior to the Tag Submittal Deadline that will not be a candidate for Reallocation. Such tags, when approved by the Tag Authority, will be marked as HOLD and must be halted.

Transaction Sub-Priority Examples

The following describes examples of Interchange Transactions using Non-firm Transmission Service sub-priority setting for ~~a~~an Interchange Transaction under different circumstances of current-hour and next-hour schedules and active MW flowing as modified by tag adjust table in E-Tag.

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

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

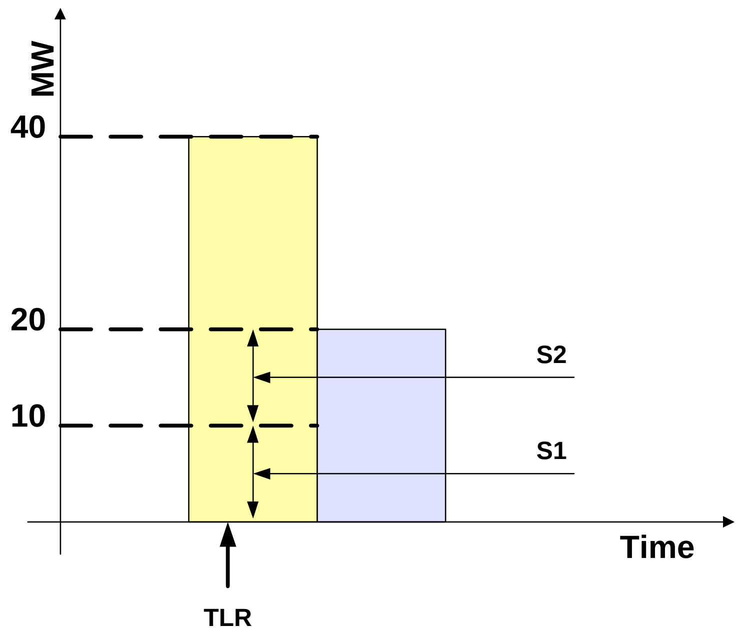


Sub-priorities for Transaction MW:

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

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

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

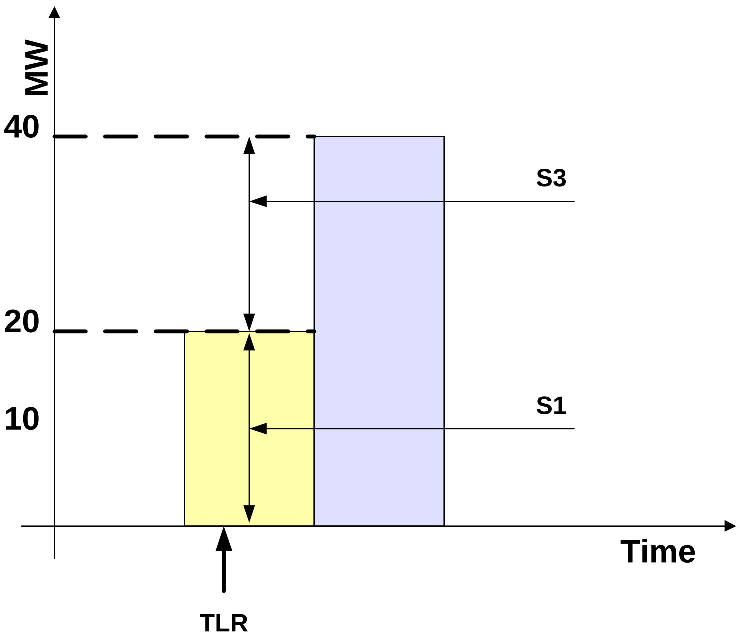


Sub-priorities for Transaction MW:

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

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

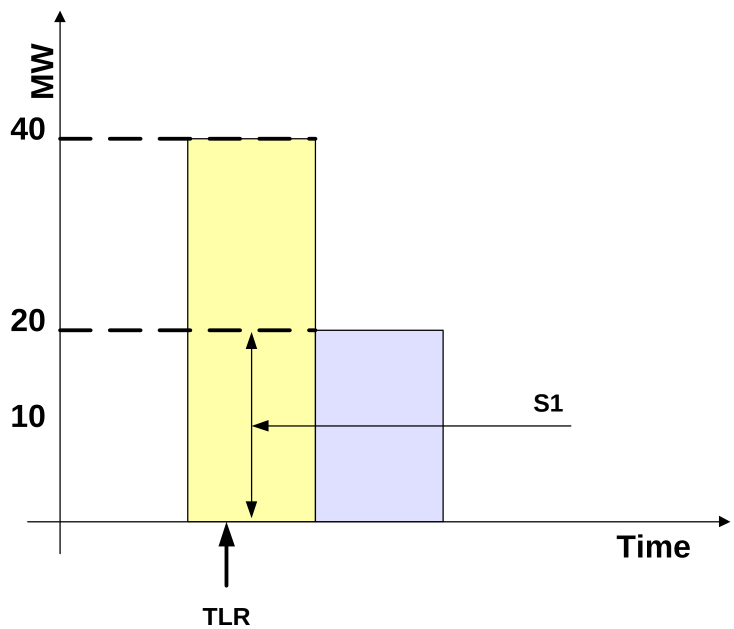
Energy Profile: Current hour	20 MW
Actual flow following curtailment: Current hour	20 MW (no curtailment)
Energy Profile: Next hour	40 MW



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

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

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

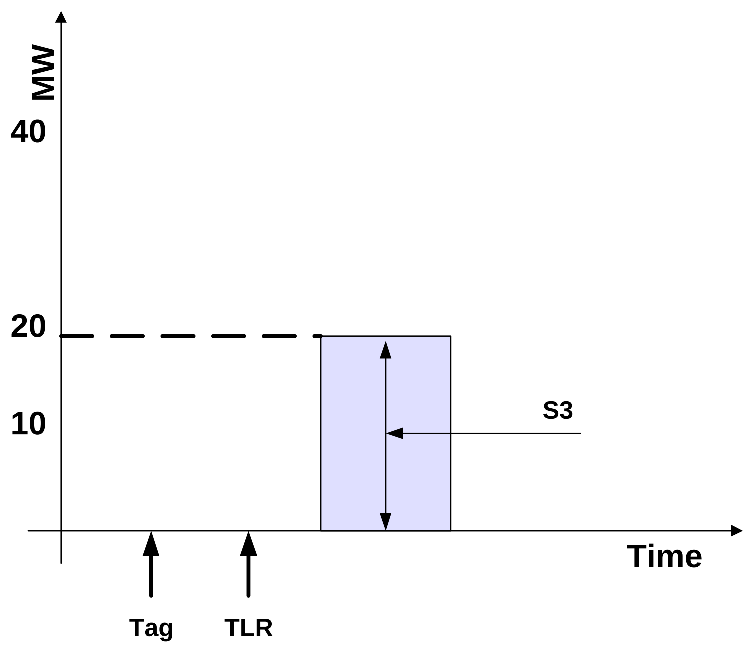


Sub-priorities for Transaction MW:

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

Example 5 — TLR Issued before Transaction was scheduled to start

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



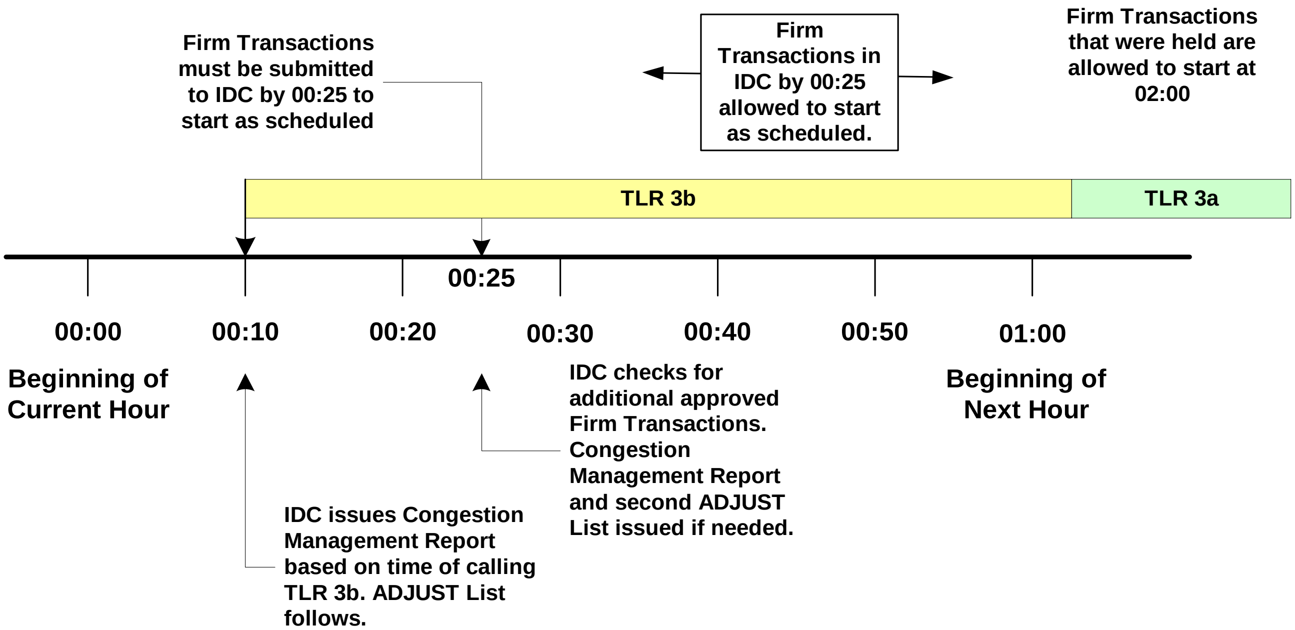
Sub-Priority	*MW Value*	*Explanation*
S1	0 MW	Transaction was not allowed to start
S2	+0 MW	Transaction was not allowed to start
S3	+20 MW	Next-hour Energy Profile is 20MW
S4	+0	Tag submitted prior to TLR

Appendix F. Considerations for Interchange Transactions

Using Firm Point-to-Point Transmission Service

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

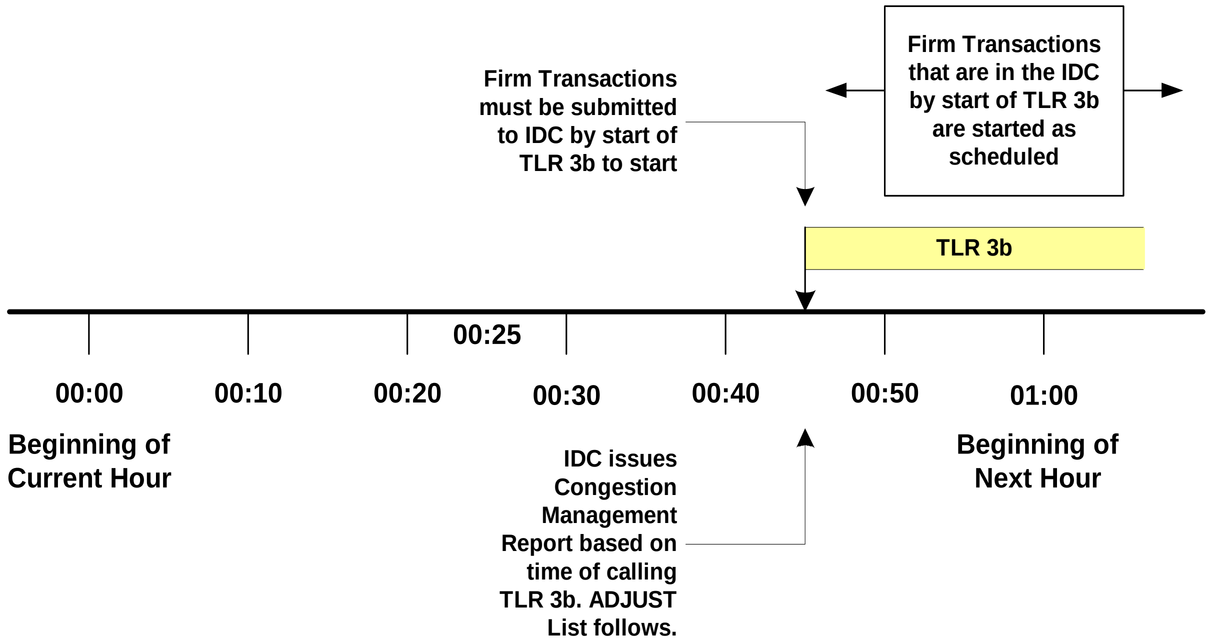
Case 1: TLR 3b is called between 00:00 and 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to IDC by 00:25.



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

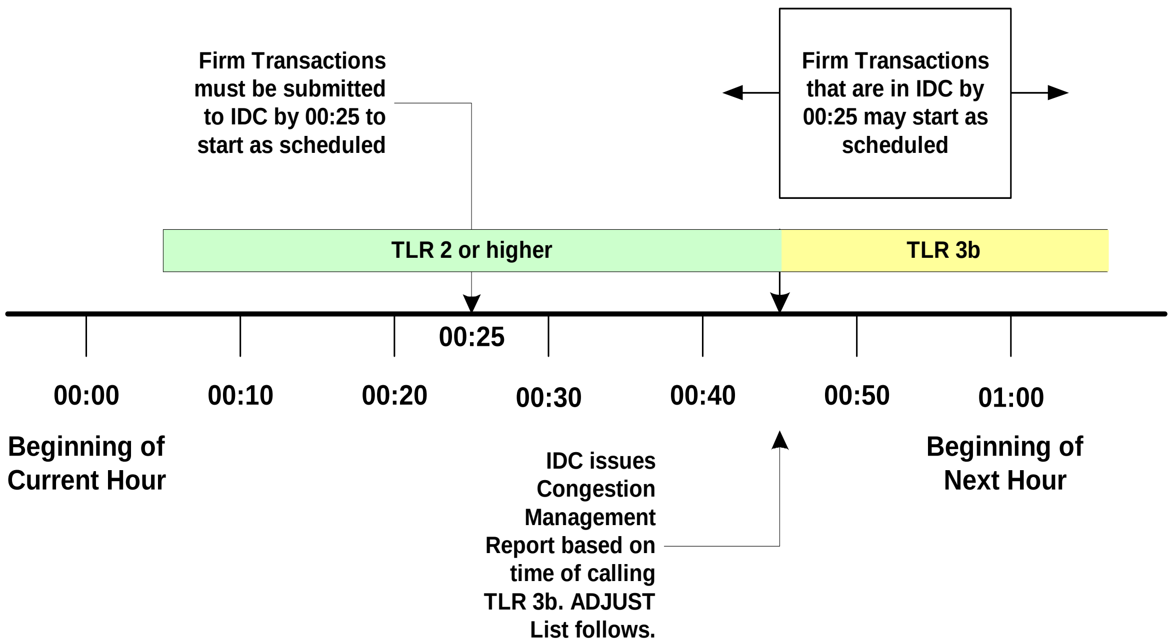
7. Once the SOL or IROL violation is mitigated, the Reliability Coordinator shall call a TLR Level 3a (or lower). If a TLR Level 3a is called:
    a. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled at 02:00.
    b. Interchange Transactions using Non-firm Point-to-Point Transmission Service that were held may then be reallocated to start at 02:00.

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



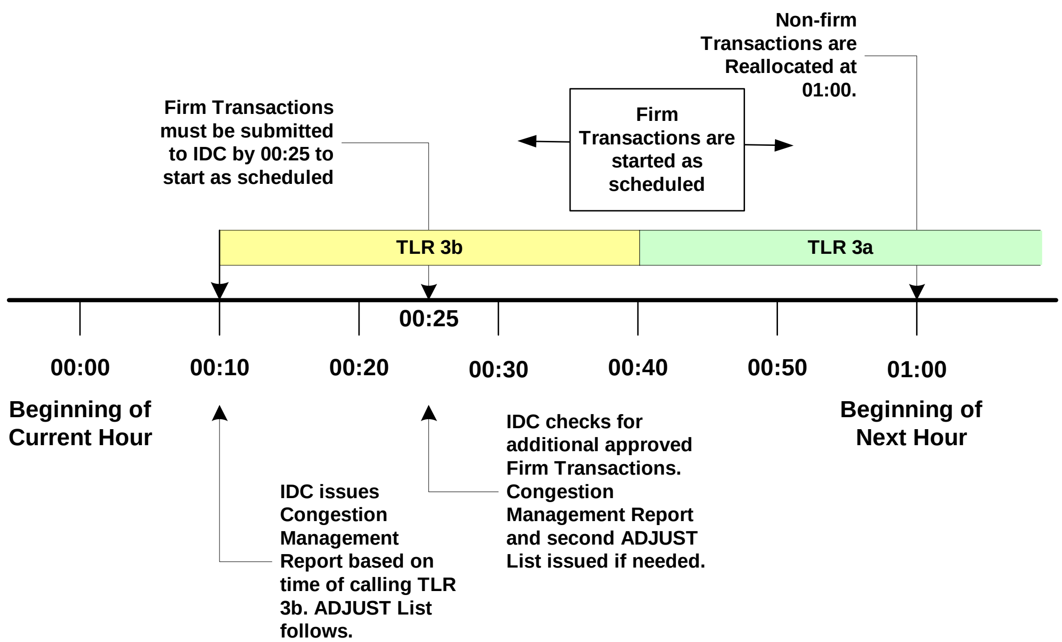
1. The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.
2. The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service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

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



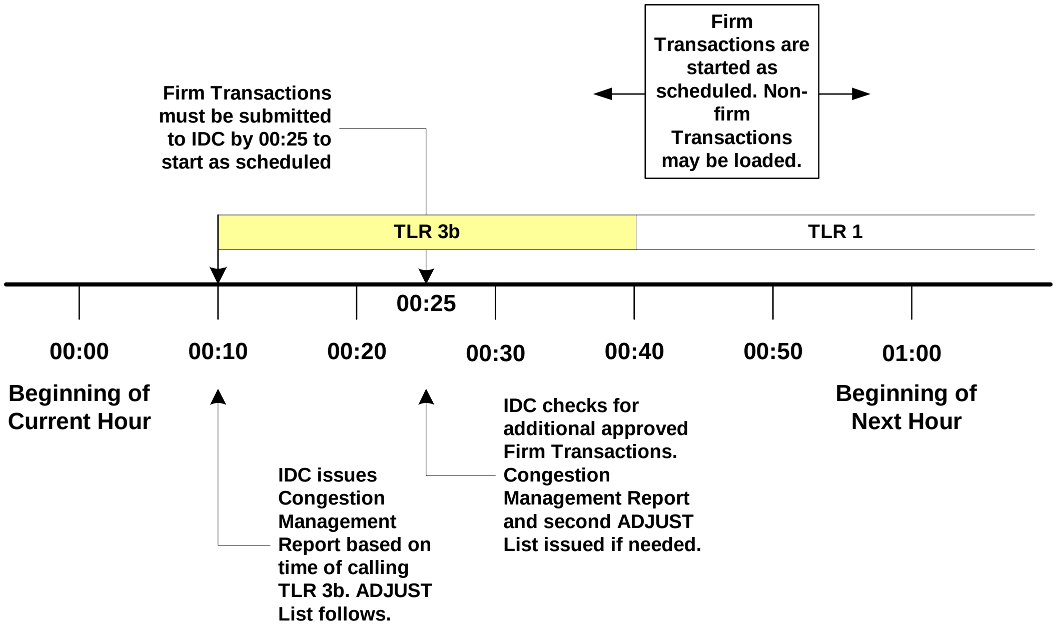
If a TLR 2 or higher has been issued and 3B is subsequently issued, then only those Interchange Transactions using Firm Point-to-Point Transmission Service that had been submitted to the IDC by 00:25 will be allowed to start as scheduled. All other Interchange Transactions are held.

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



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

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



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

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

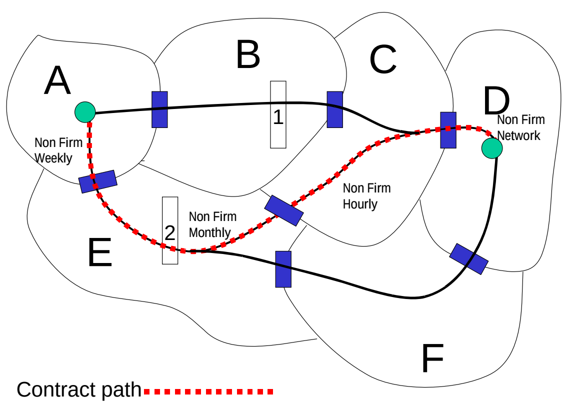
Examples

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

Scenario:

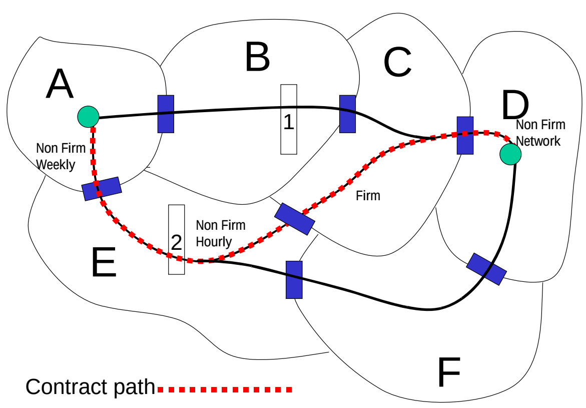
- Interchange Transaction arranged from system A to system D, and assumed to be at or above the Curtailment Threshold.
- Contract path is A-E-C-D (except as noted).
- Locations 1 and 2 denote Constraints.

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



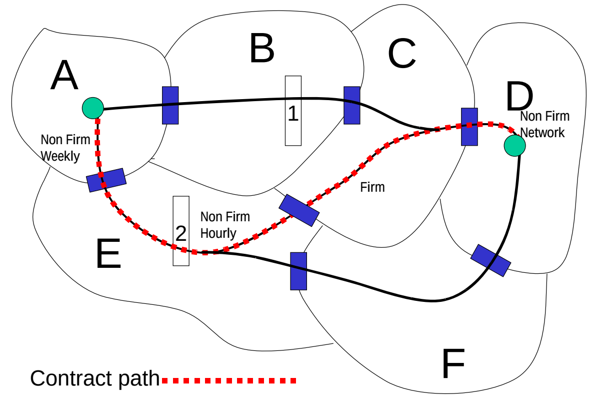
- E may call its Reliability Coordinator for TLR to relieve overload at Constraint #2.
- Interchange Transaction A-D may be curtailed by TLR action **as though it was being served by Non-firm Monthly Point-to-Point Transmission Service**, even though it was using Non-firm Hourly Point-to-Point Transmission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

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



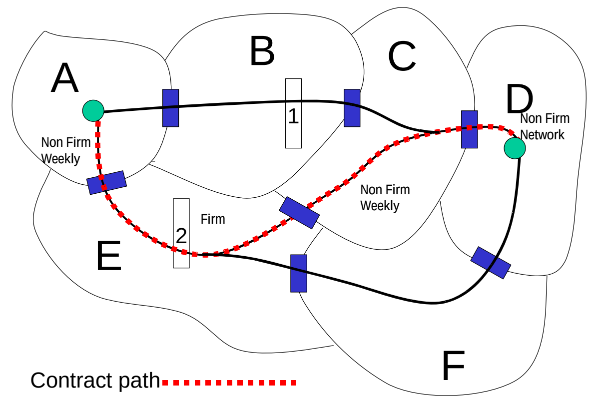
- Although C is providing Firm Service, the Constraint is not on C's system; therefore E is not obligated to treat the Interchange Transaction as though it was being served by Firm Point-to-Point Transmission Service.
- E may call its Reliability Coordinator for TLR to relieve overload at Constraint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

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



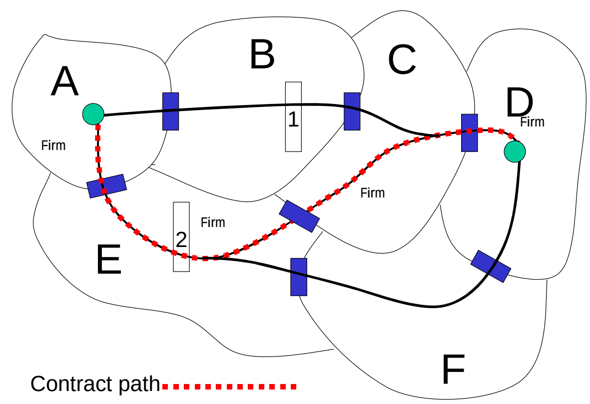
- B may call its Reliability Coordinator for TLR to relieve overload at Constraint #1.
- Interchange Transaction A-D may be curtailed by TLR action as though it was being served by Non-firm Hourly Transmission Service, even if it was using firm Transmission Service elsewhere on the path. When the constraint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

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



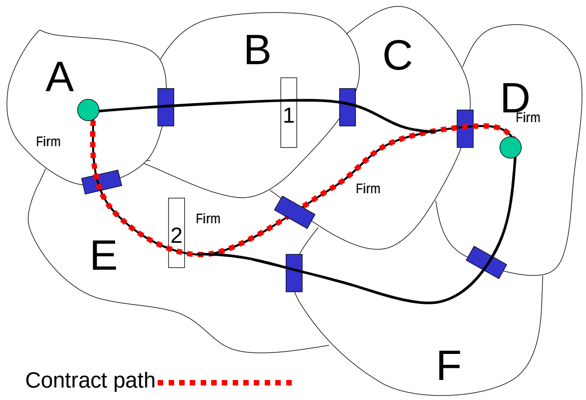
- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may then call its Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-firm Point-to-Point Transmission Service first.
- E is obligated to try to reconfigure transmission to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

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



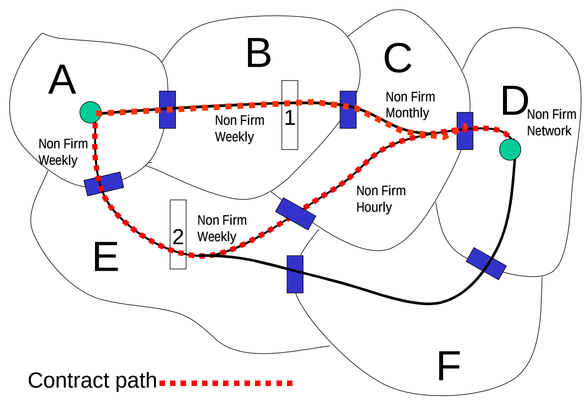
- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may call its Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-firm Point-to-Point Transmission Service first.
- E is obligated to curtail Interchange Transactions using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

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



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

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



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

A. Introduction

1. **Title:** **Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures**

2. **Number:** MOD-013-~~0~~1

3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. **Applicability:**

   4.1. Regional Reliability Organization.

5. **Effective Date:** ~~April 1, 2005~~Six months after BOT adoption.

B. Requirements

R1. The Regional Reliability Organization, in coordination with its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. Each set of Interconnection-wide dynamics data requirements shall include the following dynamics data requirements:~~:~~

R1.1. Design data shall be provided for new or refurbished excitation systems (for synchronous generators and synchronous condensers) at least three months prior to the installation date.

R1.1.1. If design data is unavailable from the manufacturer 3 months prior to the installation date, estimated or typical manufacturer's data, based on excitation systems of similar design and characteristics, shall be provided.

R1.2. Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment.

R1.2.1. Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.

R1.2.2. The Interconnection-wide requirements shall specify unit size thresholds for permitting:

– The use of non-detailed vs. detailed models,

– The netting of small generating units with bus load, and

– The combining of multiple generating units at one plant.

R1.3. Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, and static compensators.

R1.4. Dynamics data representing electrical ~~demand~~Demand characteristics as a function of frequency and voltage.

R1.5. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard MOD-010~~-0_R~~ Requirement 1.

R2. The Regional Reliability Organization shall participate in the documentation of its Interconnection's data requirements and reporting procedures and, shall participate in the review of those data requirements and reporting procedures (at least every five years), and shall provide those data requirements and reporting procedures to Regional Reliability Organizations, NERC, and all users of the Interconnected systems on request (within five business days).

C. Measures

M1. The Regional Reliability Organizations within each Interconnection shall have documentation of their Interconnection's dynamics data requirements and reporting procedures and shall provide the documentation as specified in ~~Reliability Standard MOD-013-0_R~~Requirement 2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset ~~Timeframe~~Time Frame

Data requirements and reporting procedures: on request (~~5~~five business days).

Periodic review of data requirements and reporting procedures: at least every five years.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Data requirements and reporting procedures for dynamics data were provided, but were incomplete in one of the ~~four~~five areas defined in ~~Reliability Standard MOD-013-0_~~R1.

2.2. Level 2: Not applicable.

2.3. Level 3: ~~Not applicable~~Data requirements and reporting procedures provided were incomplete in two or more of the five areas defined in R1.

2.4. Level 4: Data requirements and reporting procedures for dynamics data were not provided, or the data requirements and reporting procedures provided were incomplete in ~~two~~three or more of the ~~four~~five areas defined in ~~Reliability Standard MOD-013-0_~~R1.

E. Regional Differences

None identified.

Version History

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

A. Introduction

1. **Title: Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management**

2. **Number:** MOD-016-~~0~~1

3. **Purpose:** ~~To ensure~~Ensure that accurate, actual Demand data is available to support assessments and validation of past events and databases~~ can be performed, reporting of actual demand data is needed~~. Forecast ~~demand~~Demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, to assist in proper real-time operating, ~~load~~Load information related to controllable Demand-Side Management (DSM) programs is needed.

4. **Applicability:**

   4.1. Planning Authority.

   4.2. Regional Reliability Organization.

5. **Effective Date:** ~~April 1, 2005~~Six months after BOT adoption.

B. Requirements

R1. The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.

R1.1. The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005~~-0~~, TPL-006~~-0~~, MOD-010~~-0~~, MOD-011~~-0~~, MOD-012~~-0~~, MOD-013~~-0~~, MOD-014~~-0~~, MOD-015~~-0~~, MOD-016, MOD-017~~-0~~, MOD-018~~-0~~, MOD-019~~-0~~, MOD-020~~-0~~, and MOD-021~~-0~~.

~~**R2.** The documentation of the scope and details of the data reporting requirements shall be available on request (five business days).~~

1.1. The data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.

R2. The Regional Reliability Organization shall distribute its documentation required in Requirement 1 and any changes to that documentation, to all Planning Authorities that work within its Region.

1.2. The Regional Reliability Organization shall make this distribution within 30 calendar days of approval.

R2. The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area. The Planning Authority shall make this distribution within 30 calendar days of approval.

C. Measures

~~**M1.** The Planning Authority and Regional Reliability Organization shall each provide evidence to its Compliance Monitor that it provided data and reporting procedures per Reliability Standard MOD-016-0_R1 and MOD-016-0_R2.~~

M1. The Planning Authority and Regional Reliability Organization's documentation for actual and forecast customer data shall contain all items identified in R1.

M2. The Regional Reliability Organization shall have evidence it provided its actual and forecast customer data reporting requirements as required in Requirement 2.

M3. The Planning Authority shall have evidence it provided its actual and forecast customer data and reporting requirements as required in Requirement 3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor for Planning Authority: Regional Reliability Organization.
Compliance Monitor for Regional Reliability Organization: NERC.

1.2. Compliance Monitoring Period and Reset ~~Timeframe~~Time Frame

~~On request (five business days.)~~

One calendar year.

1.3. Data Retention

~~None specified.~~
For the Regional Reliability Organization and Planning Authority: Current version of the documentation.

For the Compliance Monitor: Three years of audit information.

1.4. Additional Compliance Information

~~None~~The Regional Reliability Organization and Planning Authority shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

~~2.1. **Level 1:** Identified the scope and details of demand, Net Energy for Load, and controllable DSM data to be reported and the reporting procedures but did not specify that consistent data is to be supplied for Reliability Standards TPL-005-0, TPL-006-0, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-0, MOD-014-0, MOD-015-0, MOD-016, MOD-017-0, MOD-018-0, MOD-019-0, MOD-020-0, and MOD-021-0.~~

~~2.2. **Level 2:** Not applicable.~~

~~2.3. **Level 3:** Not applicable.~~

~~2.4. **Level 4:** Did not identify the scope and details of demand, Net Energy for Load, and controllable DSM data to be reported and the reporting procedures.~~

2.1. **Level 1:** Documentation does not address completeness and double counting of customer data.

2.2. **Level 2:** Documentation did not address one of the three types of data required in R1 (Demand data, Net Energy for Load data, and controllable DSM data).

2.3. **Level 3:** No evidence documentation was distributed as required.

2.4. **Level 4:** Either the documentation did not address two of the three types of data required in R1 (Demand data, Net Energy for Load data, and controllable DSM data) or there was no documentation.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

0	April 1, 2005	Effective Date	New

A. Introduction

1. **Title:** **Define Regional Disturbance Monitoring and ~~Document Disturbance Monitoring Equipment~~ Reporting Requirements~~.~~**

2. **Number:** PRC-002-~~0~~ 1

3. **Purpose:** ~~To ensure~~Ensure that Regional Reliability Organizations establish requirements for installation of Disturbance ~~monitoring equipment is installed in a uniform manner~~Monitoring Equipment (DME) and reporting of Disturbance data to facilitate ~~development of models and~~ analyses of events~~.~~ and verify system models.

4. **Applicability~~:~~**

   4.1. Regional Reliability Organization.

5. **Effective Date:** ~~April 1, 2005~~Nine months after BOT adoption.

B. Requirements

R1. The Regional Reliability Organization shall ~~develop comprehensive~~ establish the following installation requirements for ~~the installation~~ sequence of ~~Disturbance monitoring equipment to ensure data is available to determine system performance and the causes of System Disturbances. The comprehensive requirements shall include all of the following~~event recording:

~~**R1.1.** Type of data recording capability (e.g., sequence-of-event, Fault recording, dynamic Disturbance recording).~~

~~**R1.2.** Equipment characteristics including but not limited to:~~

R1.1. Location, monitoring and recording requirements, including the following:

R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).

R1.1.2. Devices to be monitored.

R2. The Regional Reliability Organization shall establish the following installation requirements for fault recording:

R2.1. Location, monitoring and recording requirements, including the following:

R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).

R2.1.2. Elements to be monitored at each location.

R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:

R2.1.3.1. Three phase to neutral voltages.

R2.1.3.2. Three phase currents and neutral currents.

R2.1.3.3. Polarizing currents and voltages, if used.

R2.1.3.4. Frequency.

R2.1.3.5. Megawatts and megavars.

R2.2. Technical requirements, including the following:

R2.2.1. Recording duration requirements.

~~**R1.2.2.** Time synchronization requirements.~~

~~**R1.2.3.** Data format requirements.~~

R2.2.2. Minimum sampling rate of 16 samples per cycle.

R2.2.3. Event triggering requirements.

~~**R1.3.** Monitoring, recording, and reporting capabilities of the equipment.~~

~~**R1.3.1.** Voltage.~~

~~**R1.3.2.** Current.~~

~~**R1.3.3.** Frequency.~~

~~**R1.3.4.** MW and/or MVAR, as appropriate.~~

~~**R1.4.** Data retention capabilities (e.g., length of time data is to be available for retrieval).~~

~~**R1.5.** Regional coverage requirements (e.g., by voltage, geographic area, electric area or subarea).~~

~~**R1.6.** Installation requirements:~~

~~**R1.6.1.** Substations.~~

~~**R1.6.2.** Transmission lines.~~

~~**R1.6.3.** Generators.~~

~~**R1.7.** Responsibility for maintenance and testing.~~

~~**R1.8.** Requirements for periodic (at least every five years) updating, review, and approval of the Regional requirements.~~

~~**R2.** The Regional Reliability Organization shall provide its requirements for the installation of Disturbance monitoring equipment to other Regional Reliability Organizations and NERC on request (30 calendar days).~~

R3. The Regional Reliability Organization shall establish the following installation requirements for dynamic Disturbance recording:

R3.1. Location, monitoring and recording requirements including the following:

R3.1.1. Criteria for equipment location giving consideration to the following:

- Site(s) in or near major load centers
- Site(s) in or near major generation clusters
- Site(s) in or near major voltage sensitive areas
- Site(s) on both sides of major transmission interfaces
- A major transmission junction
- Elements associated with Interconnection Reliability Operating Limits
- Major EHV interconnections between control areas
- Coordination with neighboring regions within the interconnection

R3.1.2. Elements and number of phases to be monitored at each location.

R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:

R3.1.3.1. Voltage, current and frequency.

R3.1.3.2. Megawatts and megavars.

R3.2. Technical requirements, including the following:

R3.2.1. Capability for continuous recording for devices installed after January 1, 2009.

R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.

R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following:

R4.1. Criteria for events that require the collection of data from DMEs.

R4.2. List of entities that must be provided with recorded Disturbance data.

R4.3. Timetable for response to data request.

R4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE[1] analysis tool,

R4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files[2].

R4.6. Data content requirements and guidelines.

---

[1] IEEE C37.111-1999 IEEE Standard Common Format for Transient Data Exchange for Power Systems or its successor standard

[2] Compliance with this requirement is not effective until the IEEE Standard is approved.

R5. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.

R6. The Regional Reliability Organization shall periodically (at least every five years) review, update and approve its Regional requirements for Disturbance monitoring and reporting.

C. Measures

M1. The Regional Reliability Organization's requirements for the installation of Disturbance ~~monitoring equipment~~Monitoring Equipment shall address ~~all elements listed in Reliability Standard PRC-002-0_R1~~Requirements 1 through 3.

M2. The Regional Reliability Organization's Disturbance monitoring data reporting requirements shall include all elements identified in Requirements 4.

M3. The Regional Reliability Organization shall have evidence it provided its ~~requirements for the installation of~~ Regional Disturbance monitoring ~~equipment to other Regional Reliability Organizations~~ and ~~NERC on request (30 calendar days)~~reporting requirements as required in Requirement 5.

M4. The Regional Reliability Organization shall have evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

~~Compliance Monitor:~~ NERC.

1.2. Compliance Monitoring Period and Reset ~~Timeframe~~Time Frame

~~On request by NERC (30~~One calendar ~~days.)~~year.

1.3. Data Retention

~~None specified.~~

The Regional Reliability Organization shall retain documentation of its DME requirements for three years.

The Compliance Monitor will retain its audit data for three years.

1.4. Additional Compliance Information

~~None.~~

~~**2. Levels of Non-Compliance**~~

~~**2.1. Level 1:** The Regional Reliability Organization's Disturbance monitoring requirements do not address one of the eight requirements contained in Reliability Standard PRC-002-0_R1.~~

~~**2.2. Level 2:** The Regional Reliability Organization's Disturbance monitoring requirements do not address two of the eight requirements contained in Reliability Standard PRC-002-0_R1.~~

~~2.3. **Level 3:** The Regional Reliability Organization's Disturbance monitoring requirements do not address three of the eight requirements contained in Reliability Standard PRC-002-0_R1.~~

~~2.4. **Level 4:** The Regional Reliability Organization's Disturbance monitoring requirements were not provided or do not address four or more of the eight requirements contained in Reliability Standard PRC-002-0_R1.~~

The Regional Reliability Organization shall demonstrate compliance through providing its documentation of Disturbance Monitoring and Reporting requirements or self-certification as determined by the Compliance Monitor.

2. **Levels of Non-Compliance**

2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exist:

2.1.1 Disturbance data reporting requirements were not specified as required in R4.1 through R4.6.

2.1.2 No evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in R6.

2.2. **Level 2:** There shall be a level two non-compliance if any of the following conditions exist:

2.2.1 Technical requirements were not specified for one or more types of DMEs.

2.2.2 Requirements do not provide criteria for equipment location or criteria for monitored elements or monitored quantities as required R1, R2 and R3.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** Disturbance monitoring and reporting requirements were not available or were not provided to Transmission Owners and Generator Owners.

E. Regional Differences

None identified.

Version History

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

A. Introduction

1. **Title:** **Normal Operations Planning**

2. **Number:** TOP-002-~~0~~1

3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Transmission Operator.

   4.3. Generation Operator.

   4.4. Load Serving Entity.

   4.5. Transmission Service Provider.

5. **Effective Date:** ~~April~~ Six months after effective date of VAR-001-1~~, 2005~~.

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

~~**R14.1.**~~ Changes in real ~~and reactive~~ output capabilities.

R14.1. ~~Automatic Voltage Regulator status and mode setting.~~

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

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

A. Introduction

1. **Title:** **Voltage and Reactive Control**

2. **Number:** VAR-001-~~0~~1

~~3.~~ **Purpose:**

3. To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   ~~**4.2.** Generator Operators~~

   ~~**4.3.**~~**4.2.** Purchasing-Selling Entities.

5. **Effective Date:** ~~April 1, 2005~~Six months after BOT adoption.

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and ~~MVAR~~Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.

R3.1. Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.

R3.2. For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

~~**R3.**~~**R5.** Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.

R6. The Transmission Operator shall know the status of all transmission ~~reactive power~~Reactive Power resources, including the status of voltage regulators and power system stabilizers.

---

[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

~~R4.~~R6.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

~~R5.~~R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

~~R6.~~R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

~~R7.~~R9. Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.

~~R7.1.~~R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

~~R8.~~R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

~~R9. Each Generator Operator shall provide information to its Transmission Operator on the status of all generation reactive power resources, including the status of voltage regulators and power system stabilizers.~~

~~R9.1. When a generator's voltage regulator is out of service, the Generator Operator shall maintain the generator field excitation at a level to maintain Interconnection and generator stability.~~

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

~~R10.~~R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

~~Not~~

~~C.~~M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified~~.~~ in Requirement 4 to each Generator Operator it requires to follow such a schedule.

M2. ~~**Compliance**~~

~~Not~~The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

~~D.~~M3. The Transmission Operator shall have evidence to show that it issued directives as specified~~.~~ in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Monitoring Responsibility**

   Regional Reliability Organization.

   1.2. **Compliance Monitoring Period and Reset Time Frame**

   One calendar year.

   1.3. **Data Retention**

   The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

   The Compliance Monitor shall retain any audit data for three years.

   1.4. **Additional Compliance Information**

   The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. **Levels of Non-Compliance**

   2.1. **Level 1:** No evidence that exempt Generator Owners were notified of their exemption as specified under R3.2

   2.2. **Level 2:** There shall be a level two non-compliance if either of the following conditions exists:

   2.2.1 No evidence to show that directives were issued in accordance with R6.1.

   2.2.2 No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with R11.

   2.3. **Level 3:** There shall be a level three non-compliance if either of the following conditions exists:

   2.3.1 Voltage or Reactive Power schedules were provided for some but not all generating units as required in R4.

   2.4. **Level 4:** No evidence voltage or Reactive Power schedules were provided to Generator Operators as required in R4.

~~E.~~D. Regional Differences

None identified.

Version History

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

Exhibit B — Implementation Plan for Cyber Security Standards

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

(Revised) Implementation Plan for Cyber Security Standards CIP-002-1 through CIP-009-1

The intent of the proposed Cyber Security Standards is to ensure that all entities responsible for the reliability of the Bulk Electric Systems in North America identify and protect Critical Cyber Assets that control or could impact the reliability of the Bulk Electric Systems. This implementation plan is based on the following assumptions:

- Cyber Security Standards CIP-002-1, CIP-003-1, CIP-004-1, CIP-005-1, CIP-006-1, CIP-007-1, CIP-008-1, and CIP-009-1 are approved by the ballot body and the NERC Board of Trustees no later than May 2, 2006.
- Responsible Entities have registered.
- Cyber Security Standards CIP-002-1 through CIP-009-1 become effective June 1, 2006.

To provide time for Responsible Entities to examine their policies and procedures, to assemble the necessary documentation, and to meet the requirements of these standards, compliance assessment will begin in 2007. The table below lists specific periods by which applicable Responsible Entities must be Auditably Compliant (defined below) with each requirement.

Implementation Schedule

The following tables identify when Responsible Entities must Begin Work (BW) to become compliant with a requirement, Substantially Compliant (SC) with a requirement, Compliant (C) with a requirement, and Auditably Compliant (AC) with a requirement. Begin Work means a Responsible Entity has developed and approved a plan to address the requirements of a standard, has begun to identify and plan for necessary resources, and has begun implementing the requirements. Substantially Compliant means an entity is well along in its implementation to becoming compliant with a requirement, but is not yet fully compliant. Compliant means the entity meets the full intent of the requirements and is beginning to maintain required “data,” “documents,” “documentation,” “logs,” and “records.” Auditably Compliant means the entity meets the full intent of the requirement and can demonstrate compliance to an auditor, including 12-calendar-months of auditable “data,” “documents,” “documentation,” “logs,” and “records.” Per the standards, each subsequent compliance-monitoring period will require the previous full calendar year of such material.

The implementation plan is broken into four tables as described below. The tables specify a compliance schedule for NERC Functional Model “entities,” referred to as Responsible Entities in CIP-002 through CIP-009 standards. For organizations that are multiple Functional Model entities, each such Functional Model entity is required to demonstrate progress towards compliance according to the applicable table.

For instance, Table 1 applies to the Energy Control Center (Balancing Authority and Transmission Operator who were required to self-certify under Urgent Action Standard 1200) while the same organization's Generating Plant function (Generation Owners), would use Table 3. Likewise, this same organization's Transmission Provider function would use Table 2.

Table 1 defines the implementation schedule for Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) that were required to self-certify compliance to NERC's Urgent Action Cyber Security Standard 1200 (UA 1200).

Table 2 defines the implementation schedule for Transmission Service Providers (TSP), those Transmission Operators (TOP) and Balancing Authorities that were not required to self-certify compliance to UA 1200, NERC, and the Regional Reliability Organizations.

Table 3 defines the implementation schedule for Responsible Entities required to register during 2006.

Table 4 defines the implementation schedule for Responsible Entities registering to a Functional Model function in 2007 and thereafter.

Table 1
Compliance Schedule for Standards CIP-002-1 through CIP-009-1
Balancing Authorities and Transmission Operators Required to Self-certify to UA Standard 1200, and Reliability Coordinators

	End of 2nd Qtr 2007		End of 2nd Qtr 2008		End of 2nd Qtr 2009		End of 2nd Qtr 2010	
Requirement	System Control Center	Other Facilities	System Control Center	Other Facilities	System Control Center	Other Facilities	System Control Center	Other Facilities
Standard CIP-002-1 — Critical Cyber Assets								
R1	SC	BW	C	SC	AC	C	AC	AC
R2	SC	BW	C	SC	AC	C	AC	AC
R3	SC	BW	C	SC	AC	C	AC	AC
R4	BW	BW	SC	SC	C	C	AC	AC
Standard CIP-003-1 — Security Management Controls								
R1	SC	BW	C	SC	AC	AC	AC	AC
R2	SC	SC	C	C	AC	AC	AC	AC
R3	SC	BW	C	SC	AC	C	AC	AC
R4	BW	BW	SC	SC	C	C	AC	AC
R5	BW	BW	SC	SC	C	C	AC	AC

Table 1 (cont.)

	End of 2nd Qtr 2007		End of 2nd Qtr 2008		End of 2nd Qtr 2009		End of 2nd Qtr 2010	
Requirement	System Control Center	Other Facilities	System Control Center	Other Facilities	System Control Center	Other Facilities	System Control Center	Other Facilities
R6	BW	BW	SC	SC	C	C	AC	AC
Standard CIP-004-1 — Personnel & Training								
R1	BW	BW	SC	SC	C	C	AC	AC
R2	SC	BW	C	SC	AC	C	AC	AC
R3	SC	BW	C	SC	AC	C	AC	AC
R4	SC	BW	C	SC	AC	C	AC	AC
Standard CIP-005-1 — Electronic Security								
R1	BW	BW	SC	SC	C	C	AC	AC
R2	BW	BW	SC	SC	C	C	AC	AC
R3	BW	BW	SC	SC	C	C	AC	AC
R4	BW	BW	SC	SC	C	C	AC	AC
R5	BW	BW	SC	SC	C	C	AC	AC
Standard CIP-006-1 — Physical Security								
R1	BW	BW	SC	SC	C	C	AC	AC
R2	BW	BW	SC	SC	C	C	AC	AC
R3	BW	BW	SC	SC	C	C	AC	AC
R4	BW	BW	SC	SC	C	C	AC	AC
R5	BW	BW	SC	SC	C	C	AC	AC
R6	BW	BW	SC	SC	C	C	AC	AC
Standard CIP-007-1 — Systems Security Management								
R1	SC	BW	C	SC	AC	C	AC	AC
R2	BW	BW	SC	SC	C	C	AC	AC
R3	BW	BW	SC	SC	C	C	AC	AC
R4	BW	BW	SC	SC	C	C	AC	AC
R5	BW	BW	SC	SC	C	C	AC	AC

Table 1 (cont.)

	End of 2nd Qtr 2007		End of 2nd Qtr 2008		End of 2nd Qtr 2009		End of 2nd Qtr 2010	
Requirement	System Control Center	Other Facilities	System Control Center	Other Facilities	System Control Center	Other Facilities	System Control Center	Other Facilities
R6	BW	BW	SC	SC	C	C	AC	AC
R7	BW	BW	SC	SC	C	C	AC	AC
R8	BW	BW	SC	SC	C	C	AC	AC
R9	BW	BW	SC	SC	C	C	AC	AC
Standard CIP-008-1 — Incident Reporting and Response Planning								
R1	SC	BW	C	SC	AC	C	AC	AC
R2	BW	BW	SC	SC	C	C	AC	AC
Standard CIP-009-1 — Recovery Plans								
R1	SC	BW	C	SC	AC	C	AC	AC
R2	SC	BW	C	SC	AC	C	AC	AC
R3	BW	BW	SC	SC	C	C	AC	AC
R4	BW	BW	SC	SC	C	C	AC	AC
R5	BW	BW	SC	SC	C	C	AC	AC

Table 2
Compliance Schedule for Standards CIP-002-1 through CIP-009-1
Transmission Providers, those Balancing Authorities and Transmission Operators
Not Required to Self-certify to UA Standard 1200,
NERC, and Regional Reliability Organizations.

	End of 2nd Qtr 2007	End of 2nd Qtr 2008	End of 2nd Qtr 2009	End of 2nd Qtr 2010
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
Standard CIP-002-1 — Critical Cyber Assets				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
Standard CIP-003-1 — Security Management Controls				
R1	BW	SC	C	AC
R2	SC	C	AC	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
Standard CIP-004-1 — Personnel & Training				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
Standard CIP-005-1 — Electronic Security				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC

Table 2 (cont.)

Standard CIP-006-1 — Physical Security				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
	Standard CIP-007-1 — Systems Security Management			
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
R7	BW	SC	C	AC
R8	BW	SC	C	AC
R9	BW	SC	C	AC
Standard CIP-008-1 — Incident Reporting and Response Planning				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
Standard CIP-009-1 — Recovery Plans				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC

Table 3
Compliance Schedule for Standards CIP-002-1 through CIP-009-1
Interchange Authorities, Transmission Owners, Generator Owners, Generator Operators, and Load-Serving Entities

	December 31, 2006	December 31, 2008	December 31, 2009	December 31, 2010
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
Standard CIP-002-1 — Critical Cyber Assets				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
Standard CIP-003-1 — Security Management Controls				
R1	BW	SC	C	AC
R2	SC	C	AC	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
Standard CIP-004-1 — Personnel & Training				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
Standard CIP-005-1 — Electronic Security				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC

Table 3 (cont.)

	December 31, 2006	December 31, 2008	December 31, 2009	December 31, 2010
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
Standard CIP-006-1 — Physical Security				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
Standard CIP-007-1 — Systems Security Management				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
R7	BW	SC	C	AC
R8	BW	SC	C	AC
R9	BW	SC	C	AC
Standard CIP-008-1 — Incident Reporting and Response Planning				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
Standard CIP-009-1 — Recovery Plans				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC

Table 3 (cont.)

	December 31, 2006	December 31, 2008	December 31, 2009	December 31, 2010
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
R5	BW	SC	C	AC

Table 4
Compliance Schedule for Standards CIP-002-1 through CIP-009-1
For Entities Registering in 2007 and Thereafter.

	Upon Registration	Registration + 12 months	Registration + 24 months	Registration + 36 months
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
Standard CIP-002-1 — Critical Cyber Assets				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
Standard CIP-003-1 — Security Management Controls				
R1	BW	SC	C	AC
R2	SC	C	AC	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
Standard CIP-004-1 — Personnel & Training				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC

Table 4 (cont.)

	Upon Registration	Registration + 12 months	Registration + 24 months	Registration + 36 months
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
Standard CIP-005-1 — Electronic Security				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
Standard CIP-006-1 — Physical Security				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
Standard CIP-007-1 — Systems Security Management				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC
R6	BW	SC	C	AC
R7	BW	SC	C	AC
R8	BW	SC	C	AC
R9	BW	SC	C	AC

Table 4 (cont.)

	Upon Registration	Registration + 12 months	Registration + 24 months	Registration + 36 months
Requirement	All Facilities	All Facilities	All Facilities	All Facilities
Standard CIP-008-1 — Incident Reporting and Response Planning				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
Standard CIP-009-1 — Recovery Plans				
R1	BW	SC	C	AC
R2	BW	SC	C	AC
R3	BW	SC	C	AC
R4	BW	SC	C	AC
R5	BW	SC	C	AC

Exhibit C — Record of Development of Proposed Reliability Standards

(Provided Upon Request)

Exhibit D — Standard Drafting Team Rosters

May 16, 2006

Cyber Security Standard Drafting Team

Michael Allgeier Data Security Officer	Lower Colorado River Authority 3700 Lake Austin Blvd. Austin, Texas 78703	(512) 473-3200 Michael.allgeier@ lcra.org
David R. Ambrose SCADA System Manager	Western Area Power Administration - Rocky Mountain Region 5555 E. Crossroads Blvd. Loveland, Colorado 80538	(970) 461-7354 (970) 461-7213 Fx ambrose@wapa.gov
Laurence W. Brown Legal Affairs Director	Edison Electric Institute 701 Pennsylvania Avenue, N.W. 5th Floor Washington, D.C. 20004-2696	(202) 508-5618 (202) 508-5673 Fx LwBrown@EEI.org
Larry Bugh Manager, Information Technology	ReliabilityFirst Corporation 220 Market Avenue South Suite 501 Canton, Ohio 44702-2182	(330) 580-8017 (330) 456-5408 Fx larry.bugh@ rfirst.org
Thomas R. Flowers Manager, Control Systems Division	CenterPoint Energy P.O. Box 4567 Houston, Texas 77210-4567	(713) 207-2122 tom.flowers@ centerpointenergy.com
Greg J. Fraser Manager, System Support	Manitoba Hydro Box 815 Winnipeg, Manitoba R3C 2P4	(204) 487-5379 (204) 487-5394 Fx gjfraser@ hydro.mb.ca
Mark J. Kuras Senior Engineer, Interregional Coordination and Compliance	PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	(610) 666-8924 (610) 666-2296 Fx kuras@pjm.com
Roger Lampila IT Security Administrator	New York Independent System Operator 3890 Carman Road Schenectady, New York 12303	(518) 356-6043 (518) 356-6118 Fx rlampila@ nyiso.com
Eric J. Lee Security Specialist 1	U.S. Nuclear Regulatory Commission TWFN 11545 Rockville Pike Rockville, Maryland 20852	(301) 415-8099 (301) 415-5440 Fx exl@nrc.gov
John S.F. Lim, CISSP Systems Manager	Consolidated Edison Co. of New York, Inc. 4 Irving Place, Room 349-S New York, New York 10003	(212) 460-2712 (212) 387-2100 Fx limj@coned.com
Paul McClay Manager of Information Security	Tampa Electric Co. P.O. Box 111 Tampa, Florida 33601	(813) 225-5287 (813) 225-5302 Fx pfmcclay@ tecoenergy.com
George T. Miserendino	Triton Security Solutions, Inc. 4959 138th Circle Apple Valley, Minnesota 55124-9229	(952) 210-5563 solutions@ tritonsecsol.com

Scott R. Mix Sr. Principal Consultant	KEMA Consulting 4377 County Line Road Chalfont, Pennsylvania 18914	(215) 997-4500 scott.mix@ us.kema.com
Kurt Muehlbauer Manager of Information Assurance	Exelon Corporation 227 West Monroe, Room 1056 Chicago, Illinois 60606	(312) 394-3772 (312) 394-8888 Fx kurt.muehlbauer@ exeloncorp.com
Charles E. Noble Infrastructure Security	ISO New England, Inc. One Sullivan Road Holyoke, Massachusetts 01040	(413) 540-4232 (413) 535-4109 Fx cnoble@ iso-ne.com
Dave Norton Program Manager, Transmission IT Security	Entergy Corporation 639 Loyola Avenue MS L-MOB-17A New Orleans, Louisiana 70113	(504) 310-5763 (504) 310-5762 Fx dnorto1@ entergy.com
Bonnie R. Parker Supervisor, EMS Infrastructure	Southern Company Services, Inc. 600 North 18th Street Mail Stop 7S-8220 Birmingham, Alabama 35291-8220	(205) 257-5205 (205) 257-3689 Fx brparker@ southernco.com
James W. Sample Manager of Information Security Services	California ISO 151 Blue Ravine Road Folsom, California 95630	(916) 608-5891 (916) 351-2373 Fx jsamples@ caiso.com
Philip Scott Sobol Information Security Consultant	Corporate Risk Solutions, Inc. 20 W. 9th Kansas City, Missouri 64105	(816) 467-3238 Fx psobol@ corprisk.net
Robert L. Sypult Director, Corporate Security & Emergency Preparedness	Southern California Edison Co. 8631 Rush Street, Room 101 Rosemead, California 91770	(626) 302-7910 (626) 302-7881 Fx robert.sypult@ sce.com
Howard A. Tarler Chief, Bulk Transmission Systems	New York State Public Service Commission 3 Empire State Plaza Albany, New York 12223-1350	(518) 486-2483 (518) 473-2420 Fx Howard_tarler@ dps.state.ny.us
Thomas Turke Director of Corporate Compliance	Seminole Electric Cooperative, Inc. 16313 N. Dale Mabry Hwy. Tampa, Florida 33688	(813) 739-1244 tturke@ seminole- electric.com
John D. Varnell Technology Director	Tenaska Power Services Co. 1701 East Lamar Blvd. Arlington, Texas 76006	(817) 462-1037 (817) 462-1035 Fx jvarnell@ tnsk.com
William R. Wagner IS Director, Information Security and Business Continuity	Calpine Corporation 104 Woodmere Road Folsom, California 95630	(916) 608-3799 (916) 294-0921 Fx wwagner@ calpine.com
Lynn P. Costantini Chief Information Officer	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5731	(609) 452-8060 (609) 452-9550 Fx lynn.costantini@ nerc.net

May 17, 2006

PHASE III-IV PLANNING STANDARDS DRAFTING TEAM ROSTER

Email Address: phaseiii-ivplngsdt@nerc.com

Robert Millard Chairman	MAIN Compliance Staff 939 Parkview Blvd. Lombard, Illinois	Ph: 630-261-2621 Fx: 630-691-4222 Em: rwm@maininc.org
R. Peter Mackin Vice Chairman	Utility System Efficiencies, Inc. (USE) 2108 Marchita Way Carmichael, CA 95608	Ph:916-487-6870 Fx: 916-487-6870 Em: petermackin@useconsulting.com
William Bojorquez	ERCOT 2705 West Lake Drive Taylor, Texas 76574	Ph: 512-248-3036 Fx: 512-248-6560 Em: bbojorquez@ercot.com
Franklin Bristol	American Transmission Company, LLC P.O. Box 47 Wuakesha, Wisconsin 53187-0047	Ph: 262-506-6152 Fx: Em: fbristol@atcllc.com
W. Mark Carpenter	TXU Electric Delivery 115 West 7th Fort Worth, TX 76102	Ph: 817-215-6868 Fx: 817-215-6889 Em: mcarpen1@txued.com
James Detweiler	FirstEnergy Corp. 76 South Main Street Akron, Ohio 44308	Ph: 330-761-7797 Fx: 330-384-5349 Em: jrdetweiler@firstenergycorp.com
Roger Green	Southern Company Services Technical Services Elec. & Controls Bin B425 P.O. Box 2625 Birmingham, Alabama 35202	Ph: 205-992-7603 Fx: 205-992-5103 Em: rdgreen@southernco.com
Donal Kidney	Northeast Power Coordinating Council 1515 Broadway Floor 43 New York, NY 10036	Ph: 212-840-1070 Fx: 212-302-2782 Em: dkidney@npcc.org
E. Nick Henery	SMUD 6301 S. Street Sacramento, California 95817-1899	Ph: 916-804-0203 Fx: 916-732-6002 Em: nhenery@smud.org
Sharma Kolluri	Entergy 639 Loyola Avenue L-MOB-18C New Orleans, Louisiana 70113	Ph: 504-310-5823 Fx: 504-310-5892 Em: vkollur@entergy.com
Mark Kuras	PJM 955 Jefferson Avenue Norristown, Pennsylvania 19403	Ph: 610-666-8924 Fx: 610-666-2296 Em: kuras@pjm.com
Chuck Lawrence	American Transmission Company, LLC P.O. Box 47 Waukesha, Wisconsin 53187-0047	Ph: 262-506-6984 Fax: 262-506-6713 Em: clawrence@atcllc.com
R. Peter Mackin Vice Chairman	The Transmission Agency of Northern California P.O. Box 15129 Sacramento, California 95851-0129	Ph: 916-631-3212 Fx: 916-852-1073 Em: pmackin@navigantconsulting.com

Henry Miller	American Electric Power 700 Morrison Road Gahanna, Ohio 43230	Ph: 614-552-1125 Fx: 614-552-1645 Em: hgmiller@aep.com
Mahendra Patel	PJM Interconnection 955 Jefferson Ave Norristown, PA 19403	Ph: 610-666-8277 Fx: 610-666-2296 Em: patelm3@pjm.com
John Ratajczyk	American Transmission Company, LLC P.O. Box 47 Waukesha, Wisconsin 53187-0047	Ph: 262-506-6769 Fx: 262-506-6713 Em: jratajczyk@atcllc.com
Charles Rogers	Consumers Energy 1945 W Parnall Road Jackson, MI 49201	Ph: 517-788-0027 Fx: 517-788-0917 Em: cwrogers@cmsenergy.com
Narinder Saini	Entergy Services Inc. 5201 W. Barraque Pine Bluff, AR 71602	Ph: 870-543-5420 Fx: 870-541-4528 nsaini@entergy.com
Hector Sanchez	Florida Power & Light Company 4200 West Flagler Street Miami, Florida 33134	Ph: 305-442-5062 Fx: 305-442-5790 Em: hector_sanchez@fpl.com
Chris Schaeffer	Framatome ANP, Inc. 7207 IBM Drive CLT 2B Charlotte, North Carolina 28262	Ph: 704-382-2420 Fx: Em: Christopher.Schaeffer@framatome-anp.com
Hari Singh	American Transmission CO., LLC N19 W23993 Ridgeview Parkway W Waukesha, Wisconsin 53188	Ph: 262-506-6168 Fx: 262-506-6713 Em: hsingh@atcllc.com
Larry Smith	Alabama Power Co. 600 N. 18th Street P.O. Box 2641 Birmingham, Alabama 35291	Ph: 205-257-3270 Fx: 205-257-4684 Em: lesmith@southernco.com
Bob Stuart	Elequant 575 Market Street Suite 2025 San Francisco, CA 94105-3672	Ph: 415-978-9800, ext 202 Fx: 415-978-9810 Em: Bob.stuart@elequant.com
Lee Taylor	Southern Company Services, Inc. P.O. Box 2625 BIN 13N-8183 Birmingham, Alabama 35291	Ph: 205-257-7467 Fx: 205-257-1040 Em: ltaylor@southernco.com
Martin Trence	Xcel Energy Services 414 Nicollet Mall Minneapolis, Minnesota 55401	Ph:612-337-2152 Fx:612-337-2380 Em: martin.s.trence@xcelenergy.com
Kham Vongkhamchanh	Entergy Services, Inc. L-MOB-18C 639 Loyola Avenue New Orleans, Louisiana 70113	Ph: 504-310-5812 Fx: 504-310-5892 Em: kvongkh@entergy.com

Philip Winston	Georgia Power Company Bin # 50061 62 Lake Mirror Road Forest Park, Georgia 30297-1613	Ph: 404-608-5989 Fx: 404-608-5430 Em: pbwinsto@southernco.com
NERC STAFF		
Gerry Cauley	North American Electric Reliability Council 116-390 Village Blvd. Princeton, New Jersey 08540	Ph: 609-452-8060 Fx: 609-452-9550 Em: gerry.cauley@nerc.net
Robert Cummings	North American Electric Reliability Council 116-390 Village Blvd. Princeton, New Jersey 08540	Ph: 609-452-8060 Fx: 609-452-9550 Em: bob.cummings@ nerc.net
Mark Ladrow	North American Electric Reliability Council 116-390 Village Blvd. Princeton, New Jersey 08540	Ph: 609-452-8060 Fx: 609-452-9550 Em: mark.ladrow@nerc.net

Coordinate Interchange Standards Drafting Team Roster

Alan Boesch
Operational Compliance Supervisor
Nebraska Public Power District
P O Box 1000 2060 West Platte River Drive
Doniphan, Nebraska 68832-1000
Office Telephone: 402-845-5210
Fax: 402-845-5205
agboesc@nppd.com

Shirley M. Buckmier
Technical Specialist (Public Utility Spec)
Bonneville Power Administration - Trans
P. O. Box 491 (TMS, Vancouver, WA
98666
Office Telephone: 360-418-2583
Mobile Telephone: 360-607-9018
Fax: 360-418-8708
smbuckmier@bpa.gov

Edward J Davis
Policy Consultant
Entergy Services, Inc
L-MOB-18E
P.O. Box 61000
New Orleans, LA 70161
Office Telephone: 504-310-5884
Mobile Telephone: 504-495-2635
Fax: 504-310-5877
edavis@entergy.com

Albert M. DiCaprio
Corporate Strategist
PJM
955 Jefferson Ave
Norristown, PA 19403
Office Telephone: 610-666-8854
Dicapram@pjm.com

Joel Mickey
Manager, Market Operations Support+
ERCOT
2705 West Lake Drive,
Taylor, Texas 76574
Office Telephone: 512-248-3925
Mobile Telephone: 512-695-7567
Fax: 512-248-6560
jmickey@ercot.com

Ray Morella
Manager, Market Policy Structuring
FirstEnergy Corp
76 South Main St
Akron, Ohio 44308
Office Telephone: 330-384-5686
Mobile Telephone:
Fax: 330-384-7986
morellar@firstenergycorp.com

Michael Oatts
Manager, System Control
Southern Company Services
Mail Bin PCC-APC HQ, P.O. Box 2641
Birmingham, AL 35291
Office Telephone: 205-257-7743
Mobile Telephone: 205-585-4178
Fax: 205-257-6663
mloatts@southernco.com

Dave Robitaille
Senior Technical Officer – Cont & Agrmnts
Independent Electricity Market Operator
Station A, Box 4474
Toronto, Ontario, Canada, M5W 4E5
Office Telephone: 905-855-4126
Fax: 905-855-6129
dave.robitaille@theIMO.com

Robert D. Schwermann
Energy Coordinator
Sacramento Municipal Utility District
6301 S Street, P.O. Box 15830
Mail Stop A404
Sacramento, CA 95852
Office Telephone: 916-732-5519
Mobile Telephone: 916-798-0474
Fax: 916-732-6436
bschwer@smud.org

Karl Tammar
Administrator, Industry Affairs
NYISO
3890 Carman Road
Schenectady, NY 12303
Office Telephone: 518-356-6205
Fax: 518-356-6118
ktammar@nyiso.com

Joseph D. Willson
PJM
955 Jefferson Ave
Norristown, PA 19403
Office Telephone: 610-666-8820
Mobile Telephone: 610-659-0590
willsojd@pjm.com

Guest:
Roman Carter
Regulatory Affairs
Southern Company Generation
PO Box 2641
Birmingham, AL 35203
Office Telephone: 205-257-6027
Mobile Telephone: 205-283-8562
jrcarter@southernco.com

Inactive:
Darrel W. Richardson
Manager - Operations Research
Illinois Power Company
500 S. 27th Street
Decatur, IL 62521
Office Telephone: 217-424-6536
Mobile Telephone: 217-412-0597
Fax: 217-424-8719
darrel_richardson@illinoispower.com

Guest:
Larry Goins
Project Manager
TVA
1101 Market Street
Chattanooga, TN 37402
Office Telephone: 423-751-8103
Mobile Telephone: 423-718-9586
Fax: 423-751-2289
lgoins@tva.gov

Guest:
Robert Harshbarger
OASIS Trading Manager
Puget Sound Energy
10608 NE 4th Street
Bellevue, WA
Office Telephone: 425-462-3348
Robert.harshbarger@pse.com